Volume 59, Number 10
October 1981

0910 14 1825140 11   W50 1
COPY ONE
STATISTICAL REFERENCE INDEX
4520 EAST-WEST HWY/STE 800
WASHINGTON DC 20014

-/ C 8651 - 4

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Peak demand up 1% for 1981, survey shows

Contrary to most predictions, utility peak demand for 1981 will be only about one percent greater than last year, a survey by *EL&P* has determined.

A telephone survey of 59 utilities across the country showed that peak demand had risen this year by only 1.1 percent, with nearly all the electric companies queried presumably having reached their maximum demand for the year in early September (see table).

The survey also produced summer-to-summer peak data for 46 companies. The data here reveals that 1981 peak demand increases will be even less: up 0.4 percent for the year, startlingly less than the 4.4 percent peak load growth predicted by the Edison Electric Institute.

As reported in the August 1981 issue of *EL&P*, the seasonal 1980 peak increased 5.4 percent over the 1979 increase, and the current findings of only a 1.1 percent increase for 1981 represent a severe dampening of demand across the country. While no overriding reason could explain the slowdown, a cooler summer this year and certain power generation changes at some utilities seemed to be offered most often. Conservation was also said to have had its effect.

To give some idea of the sample size used by *EL&P* in its survey, the 46 companies reporting their summer peaks represent a combined megawatt total of 256,460 in 1980. This compares with the cumulative number of 438,150 MW used by the Edison Electric Institute as representing peak demand on the entire electric utility industry for 1980. What this means is that *EL&P* has queried 58.5 percent of the industry, if megawatts, not number of utility companies, are used as the standard of determination.

While results obtained by *EL&P* for the aggregate value of summer peak growth contrasts drastically with that of EEI (0.4% vs. 4.4%, respectively, from 1980 to 1981), the *EL&P* numbers come closer to those estimated by the National Electric Reliability Council. Adding all the summer peaks together for 1980 and 1981 (estimate), NERC comes up with 427,058 MW and 430,398 MW, respectively, or a projected summer peak demand increase for 1981 of 0.8 percent. This is much closer to *EL&P's* figure, but still greater by a factor

Continued on page 3

Will Reagan's sharpened budget ax fall?

House okays Clinch River funding; Senate to debate

WASHINGTON, D.C.—The House of Representatives has approved $228 million for construction of the Clinch River breeder reactor project, and at press time in mid-September it appeared that the Senate would likewise authorize funding.

The Energy and Water Development subcommittee of the Senate Appropriations Committee had recommended to the full committee that it adopt the House funding of $228 million but it was not clear if the committee would go along with the proposal. In mid-September, the committee had not yet scheduled a time to meet.

Although there were some vague references that a possible amendment would be introduced when the full Appropriations Committee met, earlier speculation saw funding for Clinch River sailing through the Senate in relatively becalmed waters.

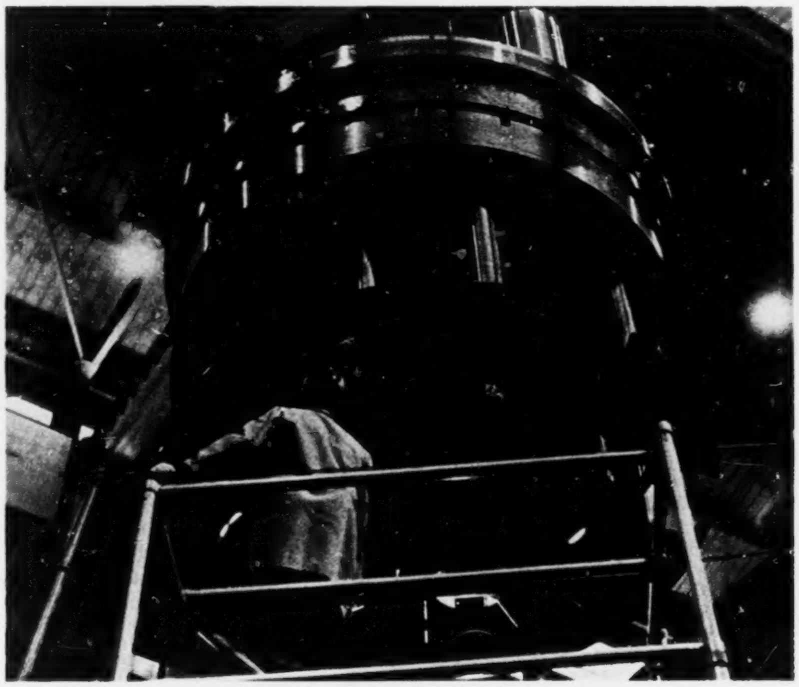
One Senate staffer noted that it was the administration that had proposed funding for the project and that the measure of opposition encountered in the House would not be experienced in the Republican Senate. Yet, the necessity for President Reagan to start on a second round of budget cuts has changed the basis of earlier predictions, notwithstanding the fact that Senate majority leader Howard Baker (R., TN) stands behind the project.

After extended debate, the House finally rejected, by 206 to 186, a proposed amendment to delete funding for Clinch River. The amendment, introduced by Rep. Lawrence Coughlin (R., PA), was said by its advocate to have been introduced on behalf of a bipartisan group of representatives who had looked into the project and found it wanting.

"This year," Coughlin said early in the debate on the floor of the House, "the administration adopted a philosophy that if an energy R&D project does not warrant private investment, it should not receive federal support.

"There followed a wholesale slaughter of

Continued on page 11



This large assembly is part of the Clinch River breeder reactor vessel closure head and has recently been completed at the Chicago Bridge and Iron Co. in Memphis, TN. The $16 million assembly forms a cover for the reactor vessel and supports associated reactor equipment. It features three eccentric, independently rotating plugs that allow access inside the reactor vessel without removal of the reactor head. The large component will be tested during 1981 and is to be shipped to the plant site in 1982.

EL&P® Late News

The Zion nuclear plant containment will not release radioactive materials even under core melt conditions, a study coordinated by the plant's owner Commonwealth Edison Company says. "Even if the plant were to incur the most serious of accidents, a core meltdown, ...there is better than a 99 percent probability that there would be no significant release of radioactive material," the utility says in describing the study. The study, which is 6,000 pages in 10 volumes, was undertaken 18 months ago after the Nuclear Regulatory Commission expressed concern that because the Zion plant was in a high population area the public might be unduly endangered by operation of the plant. But according to CECo, the NRC staff at that time did not consider Zion's "unique" design features when it made its rather generalized probability calculations. The study reportedly shows that there is only a slight likelihood of a core melt at Zion. It was also found that the most significant risk to the plant would be an earthquake more severe than the worst on record in northern Illinois. The Zion station probabilistic study, conducted by Edision scientists and outside consultants, was presented to the NRC in mid-September.

The average price of electricity in the U.S. in July was $35.74 for 500 kWh the Bureau of Labor Statistics of the U.S. Department of Labor has determined. Among the 28 metropolitan areas surveyed, Honolulu, Hawaii had the highest price, reflected in a cost of $62.22 per 500 kWh. This was followed, not unexpectedly, by New York and northeastern New Jersey. There the price for 500 kWh of electric energy was $61.87. The Seattle-Everett area in Washington state had the lowest price: $11.92 per 500 kWh, followed by the area around Portland, Oregon which had a price of $22.82 per 500 kWh.

Continued on page 2

Citibank analysis dispels popular belief

High interest rates aren't coupled to budget deficits

NEW YORK CITY—As President Reagan starts on his second round of budget cuts after being pressed to concede that the budget deficit for fiscal year 1982 will exceed his promised limit of $42.5 billion, utility managers across the country can be imagined slapping their foreheads in agony that interest rates will almost assuredly remain high.

While no one can say for sure just what interest rates will do, it now appears that deficits have been getting a lot of bad press, especially as they are believed to cause high interest rates. Citibank of New York looked into the matter recently and decided that deficits have been taking a bum rap.

Citibank found that during the 1950s, 1960s, and 1970s, interest rates tended to move inversely to movements in the federal deficit. As deficits rose, interest rates fell. This was seen to have been largely due to the fact that a weak economy reduced federal revenues. Thus, the government was borrowing while the private demand for credit dropped, thus demonstrating that the supply and demand for credit are both highly elastic.

Economists at Citibank therefore don't see a substantial "crowding out" effect on private borrowing when the federal government has to finance federal operations. This is dependent, of course, on a non-ac-

Continued on page 10

EL&P® Late News

The financial health of the electric utility industry will be probed by the National Association of Regulatory Utility Commissioners. The association has formed an *ad hoc* committee that will conduct public hearings on the question. Representatives of the industry and of the financial community, consumers, environmentalists, and other interested parties will be invited to testify and to present information. Based on the evidence presented in these hearings, the *ad hoc* committee will prepare a report and make recommendations to rectify any perceived problems regarding the financial health of the industry. The *ad hoc* committee is made up of seven state commissioners, at least one commissioner from each of the five regional affiliates of NARUC. In a resolution passed by the association, it was revealed that utility commissioners are concerned about reports of financial distress "in an industry vital to the economic welfare of the nation." Appointed to serve on the *ad hoc* committee are Edward P. Larkin, New York PSC, chairman and liaison executive; John E. Bryson, California PUC; Robert K. Koger, North Carolina Utilities Commission; J. Michael Love, New Hampshire PUC; Diane B. McCarthy, Arizona Corporation Commission; Larry J. Wallace, Indiana PSC; and Stanley York, Wisconsin PSC. The public meetings will be conducted in Hearing Room A of the Interstate Commerce Commission Building, Constitution Avenue and Twelfth Street, N.W., Washington, D.C. from 9:00 a.m. to 5:00 p.m., Thursday and Friday, October 15-16, 1981.

Radioactive material control and accounting regulations may change if the U.S. Nuclear Regulatory Commission decides to implement some of its proposed modifications in this area. The NRC wants to know if it should retain the existing requirements or adopt one of four alternative options. Present rules focus on detailed after-the-fact accounting to monitor the status of enriched uranium and plutonium fuel at manufacturing facilities. The current regulations rely primarily on conducting facility-wide inventory accounting every 60 days and making detailed comparisons of material-on-hand versus book values. Alternative options range from minor modifications that would improve the timeliness and localization of inventory accounting to the actual reform of the present material control and accounting requirements. Such reform, which is proposed in varying degrees, would decrease reliance on the after-the-fact inventory accounting now being used. Detailed descriptions of the five options being considered are contained in the*Federal Register* of September 10, 1981. The NRC is seeking public comment on the options and interested persons can respond by writing to the Secretary, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555. Comments must be received by November 9, 1981.

Omaha Public Power District settles Fort Calhoun cancellation claim brought against it by the Westinghouse Electric Corporation. The settlement was estimated at $22.5 million, according to the utility. Westinghouse sought $63 million, including interest. The second unit at the Fort Calhoun nuclear station was cancelled in 1977, three years after initial approval by the OPPD board. Said OPPD general manager Bernard W. Reznicek, "This negotiated settlement is in the best interest of the district's customer-owners, just as the 1977 decision to cancel has proved to be." Added district treasurer John Munnelly, "If we had not cancelled that unit, its cost would have risen from $800 million to as much as $3 billion, and our customer-owners would be paying 50 percent more for their electric service..."

Atlantic City's hotel-casinos will pay marginal prices for their electricity says the New Jersey Board of Public Utilities. The decision of the BPU was based on the facts that the casino hotels are both readily isolated and identifiable as a customer group with a particular load and growth characteristic, that they accounted for 70 percent of Atlantic Electric's growth in 1980 and are expected to represent 25 percent of the utility's total load growth during the balance of the decade. Considerable testimony was heard as to whether the rate-making treatment afforded the casinos would be discriminatory, but said commission Edward H. Hynes, " . . . it is my opinion that any other treatment would be discriminatory. It would force other utility customers to pay for the growth in load caused by the casino hotels."

In This Issue

New wet/dry condenser cooling technology is being developed at an EPRI-sponsored test site at Pacific Gas & Electric. **E/G** 19

Availability of coal processing machinery at Southern California Edison Company's Mohave plant has been improved through an elaborate preventive maintenance program. **E/G** 24

A machinery vibration monitoring system has been installed at Mississippi Power & Light Company's Grand Gulf nuclear station. **E/G** 27

Transformer rebuilding at Detroit Edison provides employment for handicapped workers and saves the utility money. **T/D** 31

Truck rebuilding at Pennsylvania Power & Light Company starts from the ground up. **T/D** 31

Gas insulation technology review — a look at the forefront of new developments presented at the recent IEEE/PES conference in Minneapolis. **T/D** 33

Reader Service 55

New Products 57

New Literature 61

Advertisers' Literature 63

Regulatory Review 70

Personnel 65

Management Methods 71

Calendar 17

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

JCP&L gets rate hike; some Forked River AFDC disallowed

PARSIPPANY, N.J. — The New Jersey Board of Public Utilities has given Jersey Central Power & Light Company a $110.7 million increase in base rates, and although the board provided sufficient funds to amortize most of the abandoned Forked River nuclear project, it eliminated about $27 million in credits for allowance for funds used during construction (AFUDC). The sum eliminated represented AFUDC credits accrued from the time of the March, 1979 accident at TMI-2, when the company halted construction of Forked River, until April, 1980 when it stopped accuring AFUDC on the project.

The disallowed portion of the increase will have to be written off without a directly offsetting revenue increase, General Public Utilities chairman William G. Kuhns said.

The GPU subsidiary had asked for $173 million overall base rate increase in April 1980. Last May, the New Jersey Board approved a $60 million interim increase. The current order makes that increase permanent and gives the company an additional $50 million.

While the board's action to disallow a certain part of AFUDC is important and carries serious implications for the industry, it is not unprecedented. Over three years ago, when San Diego Gas & Electric decided to abandon its Sundesert nuclear plant, about $4.5 million in AFUDC was disallowed by the California commission. It is believed that other utilities have suffered a similar fate at the hands of state commissions.

Kuhns scored the commission for rendering a decision that "runs counter to what was recommended by the administrative law judge and the BPU's own staff." He also hit what he said was an inordinate delay by the commission in making its decision.

"The board's decision to grant JCP&L even less than what the BPU's own staff recommended raises serious concerns over the future financing capabilities of the company and its ability to render adequate and reliable service to its customers," Kuhns said.

He added, "We are especially concerned about the severe impact this inadequate rate order will have on JCP&L's ability to meet its financial obligations in 1982, the greatest uncertainity being how the banks involved in the Revolving Credit Agreement will view this unsettling development."

Kuhns said he was particularly concerned with the continuing exclusion of Three Mile Island unit 1 from base rates. The commissions in both New Jersey and Pennsylvania have removed both TMI units from the base rates of JCP&L, Metropolitan Edison, and Pennsylvania Electric. This removal continues to have a severe impact in GPU's financial viability, Kuhns said.

Second quarter results showed a loss of $2.4 million, or 4 cents per share of common stock before two extraordinary items are considered (see table).

The first item is the April 9, 1981 rate order of the Pennsylvania Public Utility Commission requiring that Met Ed and Penelec cease depreciation on both TMI units. After discussions with the PUC and with the Federal Energy Regulatory Commission GPU was able to continue depreciation for TMI unit 2. This action resulted in an increase in income (after all tax effects) of $2.6 million, or 4 cents per share.

The second extraordinary item resulted from the July 23 order by the New Jersey Board of Public Utilities. Although the board granted about $50 million increase in base rates, including rates to amortize most of the cost of the cancelled Forked River nuclear project, it nevertheless disallowed related AFUDC. According to GPU, the commission's action resulted in an extraordinary charge against net income of $26.9 million, or 44 cents per share during June 1981.

At the end of June, Met Ed and Penelec again filed for annual base rate increases of $206 million and $113 million, respectively. GPU says that about half of each increase is to be used for activities related to getting TMI unit 1 back into the rate base and decontamination costs associated with the TMI units from the base rates of JCP&L, Metropolitan Edison, and Pennsylvania Electric. This removal continues to have a severe impact in GPU's financial viability, Kuhns said.

GPU REPORTS SECOND QUARTER RESULTS

Three Months Ended June 30	1981	1980
Sales of electricity (GWH)	7,412	7,391
Total revenues (000)	$476,159	$425,010
Revenues other than those related to energy costs (000)	$255,010	$231,740
Net (loss) (000):		
Before extraordinary items	$ (2,357)	$ (8,354)
Extraordinary items, net of taxes	$ (24,313)	$ –
After extraordinary items	$ (26,670)	$ (8,354)
Per share:		
Before extraordinary items	$ (.04)	$ (.14)
Extraordinary items, net of taxes	$ (.40)	$ –
After extraordinary items	$ (.44)	$ (.14)
Common shares outstanding (000)	61,264	61,264

Dividend omitted again

In August, GPU board of directors again voted to omit the quarterly common stock dividend charging the utility's continuing critical need to conserve cash. The action marked the seventh consecutive quarter GPU has not paid a dividend to its 143,000 common stockholders. A reduced dividend payment was last made to shareholders in the final quarter of 1979, GPU reported.

Perfex opens office

MILWAUKEE — The Energy Systems division of the Perfex Group, McQuay-Perfex, Inc., has opened a regional office in King of Prussia, Pa. The supplier of utility heat exchangers and feedwater heaters will service the 13 northeastern states, from Pennsylvania and Delaware north, from the office. Joe Bruno is the regional sales manager.

Peak demand growth . . . from page 1

of two.

A check with the Electric Power Research Institute determined that that organization does not have comparable near-term forecasts.

Last year, the five contiguous states of Kansas, Missouri, Oklahoma, Arkansas, and Texas endured weeks of temperatures at least 8 degrees above normal — the nominal definition of a heat wave. Starting the last week in June, 1980, portions of these states were afflicted with heat that was the most extreme in the U.S. since 1954, the National Climatic Center of the National Oceanic Atmospheric Administration reports.

It would be reasonable to posit that electric utilities in those states would have set all-time records of peak demand in 1980 and that 1981 should show a marked decline. Yet, based on the utilities in those states surveyed by *EL&P* this does not seem to be the case. Nine utilities in the region had an aggregate 1980 season peak demand of 53,763 MW and this grew in 1981 by 0.69 percent to 54,136 MW. Despite what could have been expected to be the largest peak demand last year, utilities in the region are still growing, trailing national peak demand growth only slightly for the year.

Electric companies contacted by *EL&P* that were part of last year's heat storm were Central and Southwest, Gulf States Utilities, Houston Lighting & Power, Kansas City Power & Light, Kansas Gas & Electric, Kansas Power & Light, Oklahoma Gas & Electric, Texas Utilities, and Union Electric.

It is interesting to note that Texas Utilities, which is a holding company for Dallas Power & Light, Texas Electric Service Company, and Texas Power & Light, had a peak demand that was absolutely flat from 1980 to 1981. These subsidiary companies were right in the middle of last year's Texas swelter and if any companies could have been expected to show a sharp decline in peak demand these would have been the ones. Yet according to a spokesman for the parent company, the cooler summer in 1981 was just exactly offset by the growth in the Texas area.

Blackouts in the Pacific Northwest?

Of four major utilities surveyed in the Pacific Northwest, three of them had substantial drops in peak demand as compared with 1980: Pacific Power & Light was off 9.6 percent this year, Portland General Electric had a 1981 peak load reduction of 11.6 percent, and Puget Sound Power & Light fell 9.9 percent. The other utility in the region surveyed by *EL&P*, Pacific Gas & Electric, showed a moderate increase of 1.8 percent.

As a group, these four western utilities had a slight peak demand decrease of 0.3 percent. If this calculation holds up when all the 1981 data is tabulated, and if this suggests a trend in that region, then that area of the country usually fingered as the one going dark may, in fact, have excess capacity.

It is also noteworthy that Pacific Gas & Electric Company, which had a peak demand increase this year of 1.8 percent has the two Diablo Canyon nuclear plants nearing completion, representing a combined generating increase for the area of 2,190 MW. The start-up of unit 1 is imminent. In addition, next year is expected to see the start up of unit 2 of the San Onofre nuclear plant being constructed by Southern California Edison. (SoCalEd had a peak demand increase this year of 7.0 percent over 1980). In 1983, unit 3 of the San Onofre nuclear station will go into operation. These two plants, which are currently at 98 percent and 78 percent construction completion, represent a combined total of 2,200 MW of additional capacity to the area. Overall. conservation does appear to be making a mark on the generating profile in the west.

Finally, the two Florida utilities surveyed both showed increases in peak demand as compared to last year. Florida Power & Light showed an increase of 10.3 percent and Florida Power an increase of 1.5 percent. Florida, like California, is a state that is often pictured as having a strong potential to experience power shortages. Opponents to this view often point to the fact that any shortages likely to occur in Florida are more apt to be caused by transmission problems than by generating deficits. A peak demand growth of over 10 percent, however, if such growth continues, may cause such critics to give their analyses a second look.

PEAK DEMAND*

Utility Co.	1980 season peak–MW	1981 season peak–MW	Percent change
Allegheny Power System	5,272 (W)	5,564 (W)	+5.5
American Electric Power	19,488 (W)	20,762 (W)	+6.5
Arizona Public Service	2,773	3,006	+8.4
Baltimore Gas & Electric	3,969	3,871	-2.5
Boston Edison	2,101	2,000	-4.8
Carolina Power & Light	6,139 (S)	6,402 (W)	+4.3
Central & Southwest	8,913	9,157	+2.7
Cincinnati Gas & Electric	3,154	3,140	-0.5
Cleveland Electric Illuminating	3,325	3,447	+6.9
Commonwealth Edison	14,228	13,299	-6.5
Consolidated Edison	7,276	7,063	-2.9
Consumers Power	4,540	4,703	+3.6
Detroit Edison	6,703	7,171	+7.0
Duke Power	10,364	10,602	+2.3
Duquesne Light	2,474	2,522	+1.9
Florida Power & Light	9,732 (W)	10,738 (W)	+10.3
Florida Power	4,419 (W)	5,088 (W)	+1.5
General Public Utilities	6,163 (S)	6,215 (W)	+0.8
Gulf States Utilities	5,604	5,542	-1.1
Houston Lighting & Power	10,266	10,559	+2.8
Idaho Power	1,963	2,117	+7.3
Illinois Power	3,150	3,099	-1.6
Iowa Electric Light & Power	900	914	+1.6
Iowa Resources	1,150	1,165	+1.3
Kansas City Power & Light	2,198	2,123	-3.4
Kansas Gas & Electric	1,727	1,681	-2.7
Kansas Power & Light	1,835	1,725	-6.0
Kentucky Utilities	2,185	2,150	-1.6
Long Island Lighting	3,143	3,132	-0.4
Middle South Utilities	11,769	11,448	-2.7
Montana Power	1,171 (W)	1,124 (W)	-4.0
New England Electric System	3,140 (S)	3,144 (W)	+0.1
New York State Elec. & Gas	2,138 (W)	2,170 (W)	+1.5
Niagara Mohawk Power	5,543 (W)	5,616 (W)	+1.3
Northeast Utilities	4,050	4,130	+2.0
Northern Indiana Public Service	2,224	2,183	-1.8
Northern States Power	4,873	4,678	-4.0
Ohio Edison	4,210	4,148	-1.5
Oklahoma Gas & Electric	4,260	4,420	+3.8
Pacific Gas & Electric	13,440	13,680	+1.8
Pacific Power & Light	4,226 (W)	3,820 (W)	-9.6
Pennsylvania Power & Light	4,468 (W)	4,945 (W)	+10.7
Philadelphia Electric	6,095	5,731	-6.0
Portland General Electric	3,041 (W)	2,687 (W)	-11.6
Potomac Electric Power	4,142	4,152	+0.2
Public Service of Colorado	2,772	2,810	+1.2
Public Service of Indiana	3,896	3,942	-1.2
Public Service Elec. & Gas	7,159	7,034	-1.7
Puget Sound Power & Light	3,600 (W)	3,242 (W)	-9.9
Rochester Gas & Electric	1,003	1,048	+4.5
Sierra Pacific Power	590	625	+5.9
South Carolina Elec. & Gas	2,489	2,557	+2.7
Southern California Edison	12,841	13,738	+7.0
Southern Company	19,533	19,412	-0.7
Texas Utilities	12,970	12,970	0.0
Union Electric	5,990	5,959	-0.5
Utah Power & Light	2,745	2,591	-5.6
Virginia Electric & Power	8,484	8,638	+1.8
Wisconsin Electric Power	3,346	3,290	-1.7
Wisconsin Public Service	1,109 (W)	1,133 (S)	+6.7
	322,491	326,022	+1.1

*All are summer peaking utilities except as otherwise designated.

EEI seeks new legislation for TMI cleanup financing

KANSAS CITY, MO — In effect adopting the shared cost approach outlined by Pennsylvania Governor Dick Thornburgh, the board of directors of the Edison Electric Institute has recommended that the electric utility industry raise $192 million over the next six years to help cleanup the mess at Three Mile Island.

The money, if it is ultimately collected and passed along to General Public Utilities, would pay for about 25 percent of the currently estimated clean up costs.

Last July, Thornburgh had called for a 50-50 split of funding between nationwide and area sources (see *EL&P*, September, 1981, page 2). Under the plan, nationwide sources are the nuclear industry and the federal government. Each would be responsible for 25 percent of the clean up costs, or about $190 million each. The remaining 50 percent would be shared by GPU, unpaid insurance, the Commonwealth of Pennsylvania and the State of New Jersey. In his plan, Thornburgh assumed a clean up cost of $1.034 billion minus the estimated $274 million that will have been spent through 1981.

The recommendation to the electric utility industry made by the EEI board of directors has behind it the idea that one half of the $192 million would come from the electric utility industry at large, while the second half would come from those electric companies that operate nuclear units.

In the first case, the assessment across the electric utility industry would be made on the basis of a percentage of kilowatt-hour sales by each company. In the second case, electric companies that own nuclear units will be assessed a "surcharge" based not on the kilowatt hour sales but on the nuclear capacity they have in place. Unlike the cleanup funding plan outlined by Rep. Allen Ertel of Pennsylvania, which only assesses operating nuclear plants, the EEI proposal would cover all those nuclear plants that are not operating yet but have received a construction permit. Hence, the capacity rather than the energy charge. In effect, electric utilities that have nuclear plants would be assessed twice.

For example, Commonwealth Edison, with its large nuclear inventory, would be paying $1.26 million per year for the next six years, a spokesman for the utility said. The company has calculated that its contribution based on its 1980 kilowatt-hour sales would be about $467,000 while the assessment based on its nuclear capacity would be 800,000.

One reason the EEI proposal may find favor with large nuclear utilities is that. unlike the Ertel effort, a ceiling is put on the amount a utility must contribute based on its nuclear capacity. Commonwealth Edison, for instance, is paying the maximum 5 percent of nuclear capacity because a straightforward calculation would have taken it above this amount. The EEI "lid" sets 5 percent as an upper limit here.

Outside of the recommendation by the EEI board of directors and the release to the press of information on the plan, what is being done to implement the proposal, EEI was asked. According to EEI senior vice president Jack Kearney federal legislation is being considered to transform the Institute's recommendation into a mandate.

"If all utilities were required to do this, this would assure equitable distribution of the funding commitment as we have proposed," Kearney said. As a first step, he added, it will be necessary to talk to persons on Capital Hill. As of mid-September though, no Senator or Representative was being eyed as the focus of such an effort, Kearney said.

If legislation can be passed to make the plan mandatory, EEI believes this will also help the public utility commissions to pass the costs of the utility contributions along to ratepayers.

Advertiser and advertising agency assume liability for all contents (including text representation and illustrations) of advertisements printed, and also assume responsibility for any claims arising therefrom made against the publisher. It is the advertiser's or agency's responsibility to obtain appropriate releases on any items or individuals pictured in the advertisement.

ELECTRIC LIGHT & POWER (USPS 858-860) is published monthly. Copyright 1981, by Technical Publishing, a company of the Dun & Bradstreet Corporation—all rights reserved. James B. Tafel, Chairman; John K. Abely, President; Robert L. Dickson, Executive Vice President; John R. Emery, Senior Vice President; Robert J. (Duke) Kiesel, Publisher, Editorial and Executives offices: 1301 S. Grove Ave., Barrington, IL 60010. Phone (312) 381-1840. Distributed by controlled circulation to executives and engineers in U.S. electric utilities and consulting engineering firms. To all others there is a subscription charge of $34 per year (U.S.) $40 (Canada); and £36 foreign, £62 foreign air mail). Sole agent for all subscriptions outside the U.S.A. and Canada is J.B. Tratsart Ltd., 154a Greenford Road, Harrow, Middlesex HA 13QT. England. Single copy prices $3.00 (U.S.) $4.00 (Canada); and £4 (Foreign); Second-class postage paid at Barrington, IL 60010 and at additional mailing office. Postmaster: Send form 3579 to ELECTRIC LIGHT & POWER, 1301 S. Grove Ave., Barrington IL 60010

llinois AG, City of Chicago challenge CECo rate increase

HICAGO — The Illinois Attorney eneral's office and the City of Chicago ave gone to court to contest the recent te increase secured by Commonwealth dison Company.

On July 1, 1981, the Illinois Commerce ommission granted the utility a general te increase of 14.5 percent, representing revenue hike of about $504 million (see *L&P*, August, 1981, page 23). In Novem-er, 1980, the commission had granted the ompany an interim rate hike of 8.9 per-ent and the July ruling by the ICC made at increase final while granting an addi-onal 6 percent in revenues. That interim te hike has become the focus of the Illi-ois AG's appeal.

ants interim order reexamined

"We think that before a final order is is-ued, the commission must examine the in-erim order," Jeff Paulson of the Attorney eneral's office said. He noted that the rec-rd of the rate increase case shows that the ommission did not conduct extensive re-aluation of the interim action before is-uing the final order. "We think they hould," he said.

"first" for AG

After being denied a rehearing before e commission, the Illinois AG appealed the Circuit Court of Cook County (Illinois). This is believed to be the first time that the Illinois attorney general has challenged a rate case of this type.

The AG contends the commission failed to make findings supporting the granting of interim relief in its July 1, 1981 order and thereby precluded effective judicial review of the order.

The AG also contends that the Illinois Commerce Commission has never developed or applied consistent standards for interim relief and "arbitrarily uses different standards depending on the case." Such an approach also prevents judicial review, the state argues.

Cites income excess

According to the AG, Commonwealth Edison's actual 1980 total electric generating income exceeded by $14.8 million the forecasted income upon which the commission based its interim order. "(T)o that extent the granting of interim relief was excessive and should be refunded," the state contends.

Among other things, the state also argues that the utility's operating income, operating revenues, net income, rates of return, and coverage ratios had increased and were projected to increase in the future as the result of the $390 million rate increase granted to the utility in February, 1980.

City of Chicago complaint

Chicago has also appealed the ICC's decision to grant Edison its recent rate hike. The city claims the commission erred in allowing the utility to use a forecasted test year as the basis for its rate increase request. Noting that Comm Ed used a test year ending June 30, 1982 as ratemaking data for operating and maintenance expenses, counsel for the city said, "Edison had presented only 7 months of actual data for its test year ending June 30, 1981. To allow a test year ending June 30, 1982, for any rate making purpose, amounts to compounding conjecture and speculation. All jurisdictions which regulate public utilities confine their test years to some months of actual results."

Question "future" test period

The city said many jurisdictions allow out-of-test year results only for known and measurable changes. But in this proceeding, the commission is said to have allowed out-of-test year adjustments based upon actual data for 7 months and estimated data for 17 months.

Noting that Edison has changed its in-service date for its La Salle nuclear plant and had reduced it estimated plant additions by some $76 million, the city argued that such modifications demonstrate the error of permitting completely forecasted future test years.

"Also," the city said, "the commission can take administrative notice of the in-service dates of Edison's Byron and Braidwood nuclear units." (A check of the American Nuclear Society's world list of nuclear power plants shows that the Byron and Braidwood plants have had their expected commercial operation dates pushed back 5 to 6 years since they were first announced.)

The city also hit the decision of the commission to allow unit 1 of the Dresden nuclear plant in the rate base. Because it is expected to be out of service until June, 1986, the city contends Dresden should be treated as retired.

CECo responds

Commonwealth Edison believes the court will not dismantle what the commission has put in place. "We're confident the court will uphold the decision rendered by the ICC," Edison spokesman John Hogan said. He said the commission made a "sound decision" based on proceedings that lasted 11 months and included over 100 intervenors.

Added Hogan, "The courts historically have been most reluctant to interfere with decisions made by the commission and we are confident this will continue."

Electricity prices outpace 1980 CPI, NARUC study indicates

ASHINGTON, D.C. — The price of lectricity during 1980 rose faster han the consumer price index during he same period, a report by the National Association of Regulatory Utility Commissioners has found.

Randomly sampling 50 of the 198 service territories examined in the study showed that residential electric bills increased about 17.25 percent over those bills reported in a similar NARUC study conducted a year ago. During the same period the consumer price index jumped only 11.3 percent.

COST OF 500 KILOWATT-HOURS OF ELECTRICITY IN 25 MAJOR U.S. CITIES
Winter 1980-81

Name of City	Name of Utility Company	Dec. '80	Jan. '81	Feb. '81	Total Bill (1500 KWH)	Avg. Cost in ¢/KWH (Dec.-Feb.)	Rank Among 25 Major U.S. Cities	Nation-wide Rank
New York, NY	Consolidated Edison Company	54.90	58.82	61.37	175.09	11.67	1	4
Honolulu, HI	Hawaiian Electric Company	44.87	48.31	57.68	150.86	10.06	2	11
San Diego, CA	San Diego Gas & Electric Company	48.53	48.53	51.30	148.36	9.89	3	13
Boston, MA	Boston Edison Company	46.13	46.13	49.45	141.71	9.45	4	17
El Paso, TX	El Paso Electric Company	43.46	43.86	39.54	126.86	8.46	5	26
Philadelphia, PA	Philadelphia Electric Company	38.12	38.68	38.68	115.48	7.70	6	36
Pittsburgh, PA	Duquesne Light Company	35.91	35.89	35.63	107.43	7.16	7	46
Phoenix, AZ	Arizona Public Service Company	34.61	34.61	34.61	103.83	6.92	8	52
Chicago, IL	Commonwealth Edison Company	33.32	32.69	33.56	99.57	6.64	9	68
Baltimore, MD	Baltimore Gas & Electric Company	31.86	32.50	32.50	96.86	6.46	10	77
Cleveland, OH	Cleveland Electric Illuminating Comp.	33.03	31.88	31.60	96.51	6.43	11	79
Kansas City, MO	Kansas City Power & Light Company	31.64	31.64	31.64	94.92	6.33	12	83
Detroit, MI	Detroit Edison Comp.	31.23	29.89	31.53	92.65	6.18	13	92
Columbus, OH	Columbus & Southern Ohio Electric Comp.	30.30	31.55	30.45	92.30	6.15	14	93
Dallas, TX	Dallas Power & Light Company	28.26	27.87	32.60	88.73	5.78	15	106
Denver, CO	Public Service Comp. of Colorado	27.31	28.11	26.21	81.63	5.44	16	120
San Jose, CA	Pacific Gas & Electric Company	26.37	26.37	26.37	79.11	5.27	17	131
Washington, DC	Potomac Electric Power Company	25.40	26.95	26.49	78.84	5.26	18	133
Houston, TX	Houston Lighting & Power Company	25.86	25.53	26.68	78.08	5.20	19	139
Milwaukee, WI	Wisconsin Electric Power Company	23.26	27.93	26.28	77.46	5.16	20	141
Indianapolis, IN	Indianapolis Power & Light Company	24.88	24.88	24.19	73.95	4.93	21	154
Cincinnati, OH	Cincinnati Gas & Electric Company	23.47	25.57	24.27	73.31	4.89	22	158
Oklahoma City, OK	Oklahoma Gas & Electric Company	22.80	23.27	25.17	71.24	4.75	23	161
Atlanta, GA	Georgia Power Company	23.51	23.51	23.51	70.53	4.70	24	165
St. Louis, MO	Union Electric Company	21.78	21.78	21.78	65.34	4.36	25	173

Source: Data provided to the NARUC by its member State Commissions.

Using a 500 kWh per month consumption level as the basis of comparison, the random sample indicated that electricity costs climbed from about 5.4 cents per kWh to 6.33 cents per kWh during the 12-month period.

This is the third nationwide winter survey of residential electric bills released by NARUC. The report contains winter 1980-81 residential electric bill comparisons for the largest service territories of the major regulated electric utilities in 49 states, the District of Columbia, and Guam. (The state of Nebraska does not regulate electricity).

The report, which is said to be the most comprehensive residential electric bill survey yet conducted by NARUC, provides a national ranking of each service territory included in the study.

The chart shows that of the 25 major U.S. cities, residents of New York City paid the highest average cost in cents per kWh (11.67 cents) from December to February. Other high average costs were paid by residents of Honolulu, HI (10.06 cents); San Diego, CA (9.89 cents); and Boston, MA (9.45 cents). Of the 25 selected major U.S. cities, St. Louis, MO was found to have the lowest cost per kWh, with residents there paying 4.36 cents per kWh. Other low bills were found in Atlanta, GA (4.70 cents); Okalhoma City (4.75 cents); and Cincinnati, OH (4.89 cents).

Rates vary considerably

The report documents that residential electricity bills vary widely and depend on the service territory in which the customer is located. In 12 service territories, for example, consumers are paying more than 10 cents per kWh, while in 16 other service areas, consumers are paying less than 4 cents per kWh. The actual cost to the consumer, however, is dependent not only on the actual usage level but on applicable state sales taxes as well.

A copy of the 210-page report may be obtained from NARUC, P.O. Box 684, Washington, D.C. 20044. The price is $10.75 per copy.

NOTE

ONLY THE FOLLOWING PAGES OF THIS

PUBLICATION HAVE BEEN FILMED

p. 1-3, 6, 21, 24-25, 28,

68.

C 8650-4

Volume 59, Number 11
November 1981

0911 25 1830645 1 W JPK
JOSEPH MC NALLY
CONGRESSIONAL INFORMATION
SERVICE INC
4520 EAST-WEST HWY-STE 800
WASHINGTON DC 20014

Electric Light & Power
THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Atlantic Electric is 1981 award utility

Atlantic Electric Co. has been named *Electric Light & Power*'s 1981 Outstanding Electric Utility of the Year. The utility was chosen by a panel of industry judges to be the 13th winner of the annual award.

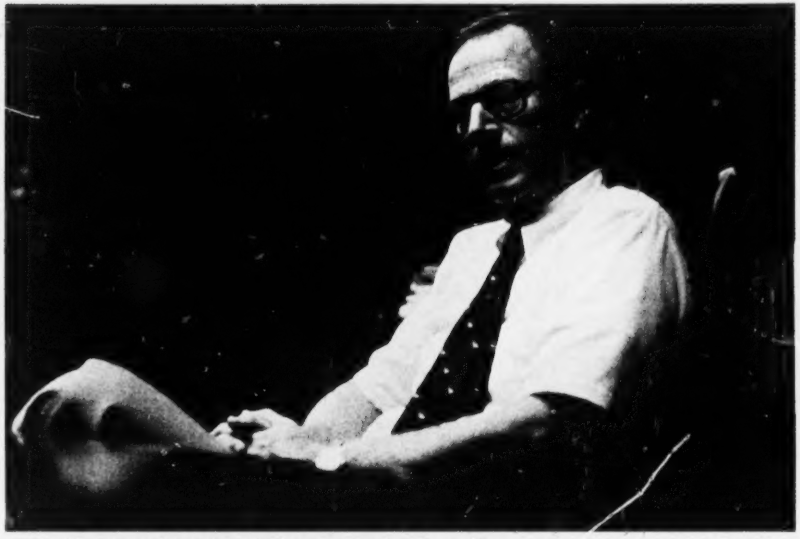
EL&P Editor Robert Lincicome said the award was based on an impressive three-year financial record, the utility's leading role in converting oil-fired generating capacity back to coal, and an innovative communication program.

Utility president and chief executive officer John Feehan expressed appreciation for the award and noted that the company faces even stiffer challenges in coming years. With growth in demand in recent years sparked by the introduction of nine gambling casinos and hotels in Atlantic City, the utility must deal with unprecedented capital requirements that total twice the company's current assets in the next decade, Feehan said. (One interesting technique being explored for raising capital at Atlantic Electric is explained in the article below.)

Over the past three years the utility has recorded an almost unmatched record of improvement in earnings: a seven percent gain in 1978 to $2.21 a share; another seven percent increase in 1979 to $2.36 a share; and an eleven percent rise in 1980 to a record $2.36 a share.

Part of the impressive earnings record is due to the company's swift replacement of imported oil with coal as a power plant fuel. When the company's largest generating station, the B.L. England station, was converted to oil for environmental reasons in the early 1970s the company retained all the coal-burning equipment and kept it maintained. The station was back on coal one month after the 1973 Arab oil embargo, making it the first utility to convert back. The company is now converting its other major station, the Deepwater plant, back to coal also and is aiming at reducing its oil dependence to 10 percent.

The special report on Atlantic Electric begins on page 13.


Atlantic Electric president John Feehan explains how he and his management team achieved such impressive corporate results in recent years.

European equipment suppliers offer low-cost power plant financing

A highly unusual foreign financing and supply deal is being negotiated for Atlantic City Electric Co.'s proposed new 290-MW coal-fired Cumberland power plant, according to utility president John Feehan. By using largely foreign equipment for the plant, the utility hopes to get access to foreign capital at money costs much lower than those now prevalent in the U.S., shaving as much as $100 million off the $550 million estimated cost of the power plant, Feehan revealed during an interview .

This is not the same as the "Eurodollar" or "Eurobond" financing at interest rates of 17 or 18 percent which is becoming increasingly popular with U.S. utilities. In those deals the interest rates are at best only slightly better than those in the U.S. Atlantic City Electric wants the borrowing to take place at substantially lower rates by going through foreign suppliers.

Two European suppliers, Cogenel ("French General Electric") and Brown-Boveri, the Swiss firm, have responded so far, reports Feehan. One of the proposals was extremely broad based, covering equipment, construction, financing, "everything", according to the executive.

Feehan says the search for lower interest rates is part of the company's overall program to do all it can to slash capital costs. Atlantic Electric is trying to dampen demand to avoid, or at least put off the need to build the new power plant. But if demand continues to grow, Feehan says that a large block of new company-owned capacity will be needed in the late 1980s. He's not sure that financing such a project is even possible at current U.S. money rates.

Access to the much lower interest rates in some European countries may make it possible to proceed with the generating project, he explains. "We'd like to go American, but these proposals may unlock the door."

Company officials are weighing the risks of extensive reliance on a foreign supplier. They're evaluating equipment quality, servicing, spare parts availability, and other factors. "Our knee-jerk reaction," says Feehan, "is not to go foreign. But it's a very interesting prospect. We have to be flexible."

Paul Hughes, a manager with Brown-Boveri Corp.'s U.S. office in North Brunswick, N.J. said he would prefer not to discuss the details of the company's proposal for the Atlantic City Electric project because formal bids have not been made yet. Hughes explained that utility officials had solicited an equipment bid including a request that Brown-Boveri aid in financing.

The utility managers are seeking access to money at Swiss bank loan rates, said Hughes, which are currently about seven percent. "We're not in any position to get any special deal for Atlantic City Electric," said Hughes. "We're using our knowledge and connections as a Swiss manufacturer. These are bank loans. All it is, is making the introductions. These are not supplier credits."

Hughes said that Brown-Boveri had not made a turnkey proposal. The company does build power plants on a turnkey basis, but only in places such as the Far East or the Mideast, not in the U.S. The firm does not like to engineer U.S. power plants because it doesn't want to "tread on the toes" of U.S. architect-engineering firms, Hughes explained. He noted that the Swiss company was recently awarded a $30 million contract for a turbine-generator for a U.S. coal-fired power plant by the Grand River Dam Authority of Vinita, Oklahoma. The company is not looking to go beyond its normal scope of equipment supply or to provide engineering on coal-fired power plants in the U.S.

A spokesman for Utility Power Corp-Corp. said his firm declined to respond to the request to make a proposal for the Cumberland project. The company is partially owned by Siemens, the West German equipment supplier. The spokesman said that the Atlantic City request was unusual in that they were seeking to build a power plant with equipment purchased in Europe with European financing. He said that his firm did not want to participate because there would be too many opportunities for misunderstanding with all European equipment and a U.S. design.

EL&P® Late News

President Reagan issued his nuclear policy statement in early October and the policies and actions he announced were aimed at what he termed "a revitalization of the U.S. industry's effort to develop nuclear power." There reportedly will be an effort to streamline the time it takes to construct and license a nuclear plant—from 10-14 years to 6-8 years. To those who thought the President might retreat from his earlier support of the Clinch River breeder reactor—as he scoured the bureaucratic landscape looking for additional budget cuts—Reagan offered this: "I am directing that government agencies proceed with the demonstration of breeder reactor technology, including completion of the Clinch River Breeder Reactor. This is essential to ensure our preparedness for longer-term nuclear power needs." The President lifted the ban on commercial reprocessing and has ordered a study to assess the feasibility of obtaining economic plutonium supplies for the Department of Energy through competitive procurement. He said DOE and industry must toward deployment of a means of storing and disposing of commercial high-level radioactive waste." Finally, the President said he has formulated a task force that will seek to identify any and

Continued on page 2

Reagan reversal

Administration to push for $100 million for TMI cleanup

WASHINGTON, D.C.—The Reagan Administration has decided it will recommend over $100 million for the cleanup of the contaminated Three Mile Island reactor.

The decision constitutes a reversal of an earlier position assumed by the White House that it should only be responsible for waste management and some research and development activities with respect to the downed reactor.

Word of the possible federal funding came through two statements made by budget director David Stockman. After attending a fund raising event in Pennsylvania on October 9 Stockman held a local press briefing where he revealed that the federal government would contribute over $100 million to help clean up the mess at TMI-2.

The wire services picked up the remarks and Stockman was questioned about it again at the White House the next day. He repeated the government's planned commitment.

Continued on page 6

EL&P® Late News

all obstacles that currently stand in the way of the increased use of nuclear power. The task force is to report to the President by September 30, 1982, informing him not only of impediments to nuclear power development but steps that are needed to overcome them. "Eliminating the regulatory problems that have burdened nuclear power will be of little use if the utility sector cannot raise the capital necessary to fund construction of new generating facilities," Reagan concluded. "We have already taken significant steps to improve the climate for capital formation with the passage of my program for economic recovery. The tax bill contains substantial incentives designed to attract new capital into industry."

The federal government should take title to spent fuel and rad-wastes in return for a concession by nuclear utilities that they will pay a fee based on nuclear kilowatt hours sold. This was one part of Sherwood Smith's testimony recently on behalf of the electric utility industry before a joint hearing of the Senate Environment and Public Works Committee and the Senate Energy Committee. Smith, who is head of Carolina Power & Light and chairman of the Edison Electric Institute's policy committee on governmental affairs, also called for legislation in the area of nuclear waste management. "We firmly believe that the legislation should authorize and direct the secretary of energy to enter into contracts with all nuclear plant operators by which the government agrees to take title to and responsibility for radioactive wastes or spent fuel by a specific time, in return for the commitment of the utility to collect from its customers and pay to the treasury a fee of one mill per kilowatt-hour of nuclear generated electricity for all nuclear fuel removed from nuclear reactors," Smith said. He said that legislation was necessary to ensure policy stability amid changes of administration and changes in Congress. Legislation, Smith added, could also work to define the role of the states and Indian tribes so that disputes and delay could be avoided. Finally, legislation would clarify the issues needed to prepare an environmental impact statement. Smith said that utilities support the concept of a test and evaluation facility that does not delay the overall geologic respository program or add significant costs to the waste management program. He also supported the establishment of a federal interim spent fuel storage program.

NARUC has formed an *ad hoc* committee on utility diversification. The committee, which consists of eight members, will review the 1972 report prepared by NARUC's *ad hoc* committee on non-utility investments. This diversification committee of the National Association of Regulatory Utility Commissioners will revise the 1972 report as necessary in order to increase its current value to the regulatory community. The *ad hoc* committee on utility diversification includes the following members: Stanley York, chairman of the Wisconsin Public Service Commission and chairman of the *ad hoc* committee; Thomas H. Fitzpatrick, chairperson of the Connecticut Public Utilities Control Authority; Edward B. Hipp, commissioner, North Carolina Utilities Commission; and Francis J. Riordan, commissioner of the New Hampshire Public Utilities Commission. Also serving on the *ad hoc* committee are Henry Moak Rollins, commissioner, Texas PUC; Richard E. Schuler, deputy chairman, New York PSC, Larry J. Wallace, chairman, Indiana PSC; and John W. Winters, Sr., commissioner, North Carolina Utilities Commission.

In This Issue

Editorial 4

Atlantic City Electric Co. is the winner of the 1981 utility of the year award ... 13

Trends in the sulfur market toward higher prices and tighter supply may affect utility decisions on the type of scrubber to be used on coal-fired power plants. **E/G** 21

Repowering a reheat cycle, oil- or gas-fired power plant with a coal-fueled combined cycle may make economic sense, says Westinghouse. **E/G** 24

A new scrubber technology that provides particulate and sulfur dioxide removal in a single-state venturi is working well at Arizona Public Service. **E/G** 26

Creativity in specialized equipment and scheduling speeds construction of 230-kV T-line, H-frame towers to pace of 28 towers per day. **T/D** 47

PCB-capacitor rupture possibilities can be reduced economically with existing devices and better fusing techniques. **T/D** 50

Three new developments in herbicide application techniques promote economy and improve public acceptance of ROW maintenance and growth control. **T/D** 54

IEEE/PES Conference and Exposition held in Minneapolis was a big show with emphasis on new products and improved technical communications. **T/D** 60

Reader Service 85

New Products 87

New Literature 88

Advertisers' Literature 92

Personnel 94

Regulatory Review 104

Management Methods 105

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

Diablo Canyon protestors to regroup while design problem delays startup

Dan Utroska
Associate Editor

AVILA BEACH, CA— The anti-nuclear protestors at the Diablo Canyon nuclear plant got an unexpected assist in September as the revelation of a seismic design problem threatened to delay startup of the reactor for as much as six months.

In addition, even as protestors were attempting to block access to the plant, Governor Brown of California, an avowed opponent of Diablo Canyon, filed a suit in the U.S. Court of Appeals for the District of Columbia Circuit charging that the Nuclear Regulatory Commission had issued the low power testing license for the plant contrary to applicable laws and statutes.

Annulus braces questioned

"We have uncovered a discrepancy that has possible safety concerns," a spokesman for Pacific Gas & Electric Company said. On September 27, utility personnel found that a reference diagram for unit 2 at Diablo Canyon had been used in the design and construction of unit 1. The reference diagram was used to determine the vertical acceleration and frequency response factors of equipment braces in the annulus. The error was discovered when utility personnel, working on unit 2, found that the application of annulus brace data for that reactor was off by a mirror image. Since unit 1 plant layout is a mirror image of unit 2, it was concluded that a design error had occurred. PG&E notified the NRC.

It was not clear in mid-October the extent of the delay that would be experienced as the NRC considered the matter. The utility had set up a meeting with the NRC to inform the agency of the results of its new calculations after the mistake had been identified. But the utility subsequently asked for more time and a meeting between PG&E and the NRC had been reset for October 9.

The significance of the error, while still to be determined, touched on the very issue that Abolone Alliance protestors fear: the capability of the Diablo Canyon nuclear plant to withstand an earthquake. According to Darrell Eisenhut, director of the NRC's Division of Licensing, the Diablo Canyon annulus brace design data used in construction of the plant would determine how equipment there would respond during a seismic event.

The PG&E spokesman said that from a technical standpoint, the situation could be resolved in a couple of months, but what the utility fears is that the NRC will decide to reopen hearings on the plant. This would extend the time the plant is on hold.

Abolone Alliance: success redefined

The Abolone Alliance, a loosely-knit group of about 60 "safe-energy" organizations, had originally set out to force the utility and the Nuclear Regulatory Commission to sign an agreement that Diablo Canyon would never operate as a nuclear plant (see *EL&P*, September, 1981, page 2). The groups' approximately 15 day protest at the site, where about 2,000 demonstrators were arrested, failed to accomplish this, but the annulus brace problem has given the Alliance a chance to retreat and regroup. "We are by no means finished," Alliance spokesperson Marilyn Apuzzo told *EL&P*. She said that a statewide conference had been set for the weekend of October 10-11 to discuss plans for sending Diablo Canyon participants back to their communities in an effort to mobilize a renewed contingent of demonstrators. "The blockade is the end of phase 1," Apuzzo said.

Although the Alliance did not get the agreement it sought, the group believes it has heightened the visibility of the dangers of nuclear power. Alliance spokesperson Apuzzo reiterated a remark attributed to a PG&E representative, that "without the blockade, we would have read about (the brace design problem) on page 33 of the newspaper."

The Alliance is sued

Although Pacific Gas & Electric said the demonstration had caused "no significant slowdown in fuel loading, low-power testing preparations or construction of the unit," the Pacific Legal Foundation, representing a group of aggrieved organizations and individuals, believes a case can be made that the utility has incurred extraordinary expenses and should be compensated. Accordingly, the foundation has filed suit seeking recovery of PG&E costs for such items as special buses that were needed to bring workers through the blockade, the helicopter used for that purpose and the extra security personnel that had to be employed.

This, according to Pacific Legal Foundation attorney Hal Hughes, is one part of the $1 million lawsuit that was filed against the Alliance on September 25. The other part seeks to recover the costs to area taxpayers for the extra law enforcement efforts caused by the blockade.

The Pacific Legal Foundation, a conservative organization, says it has the support of four groups and five individuals in its suit against the Alliance. Included in the organizations providing support are Consumer Alert, said by Hughes to be a national, nonprofit consumer organization, the Voice of Energy, and a San Luis Obispo coalition of taxpayers, farmers, and others called the "Countywide Coalition for Less Government."

Leading the individuals supporting the PLF suit is California state congresswoman Carol Hallett. Mrs. Hallet represents the district in which the demonstration took place. According to Hallett spokesman Jack Stevens the lawsuit is not about the pros and cons of nuclear power but is a "test of whether persons can demonstrate illegally and then make taxpayers pay for it."

The broad basis of the suit rests on the "nuisance" the protestors caused, Stevens said. Claiming that the illegality of the protest precludes the demonstration from being viewed as a First Amendment expression, Stevens said the demonstrators blocked roads and generally caused some taxpayers to do without normal law enforcement services while personnel were transferred to the nuclear plant site. Is such a lawsuit unique, Stevens was asked. "I have no knowledge that this has even been tried before," he said.

Alliance undeterred

According to Alliance spokesperson Marilyn Apuzzo, the $1 million lawsuit against the anti-nuclear group will have no inhibitory effect on planned actions. She said that a number of attorneys had already volunteered their legal services and that as a result of the publicity of the Diablo Canyon blockade, persons from all over the country were sending in money. "We can deal with it," she said.

Branding Rep. Hallet's action as a "scare tactic" and an effort "to dissuade our action," Apuzzo said the lawsuit was little more than a "political ploy" on Hallett's part. "She wants to make an issue out of it in her run for Lt. Governor," Apuzzo said, but Hallett spokesman Jack Stevens said Mrs. Hallett had not declared for the office of Lt. Governor and that the congresswomen was only one party to a lawsuit that was being brought by numerous independent plaintiffs.

Deregulation may help, Mellon Institute says

Kilowatt hours too costly to compete, study claims

The sale of centrally-generated electricity could be in for some difficult times if economic forces move to displace political ones in U.S. energy policy.

This is a major conclusion of a recent study by the Mellon Institute that undercuts the conventional wisdom surrounding the so-called energy crisis. “Shifting from a political to an economic paradigm for energy does more than demonstrate the falseness of many of our beliefs about energy,” the report declares. “It points the way toward new means of effective action in meeting energy service needs.”

The study, called “Eight Great Energy Myths,” is an update of a 1979 Institute analysis that assumed the elimination of regulations affecting energy choices. Consumers really don't care about kilowatt hours or Btu's, the earlier study found, so long as they can obtain comfort and convenience in their homes, and steam and operating machines in their factories. When energy is viewed in this way, fuel and electricity are seen as only one part of what is needed to provide useful services. In making a room comfortable, for example, components such as a furnace, a thermostat, duct work, insulation, and numerous other support items are also required. What is important, the study found, is putting these together so that they reflect the lowest cost. This often means a reduced fuel component in providing the total service.

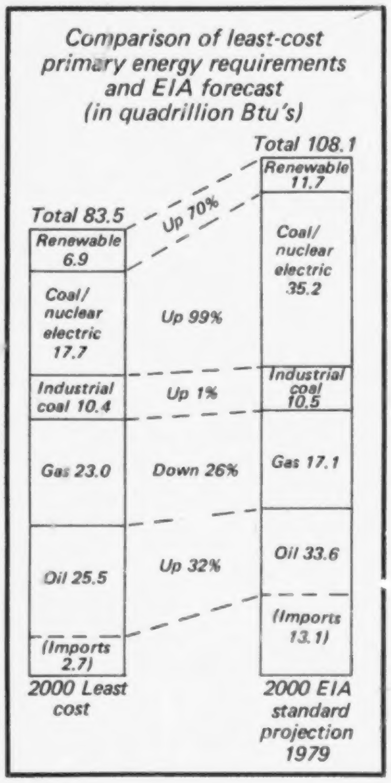
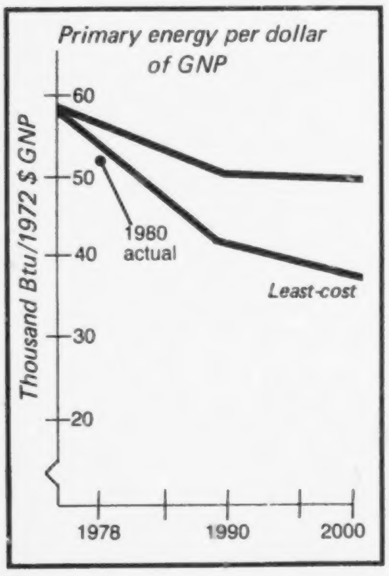


Figure 1

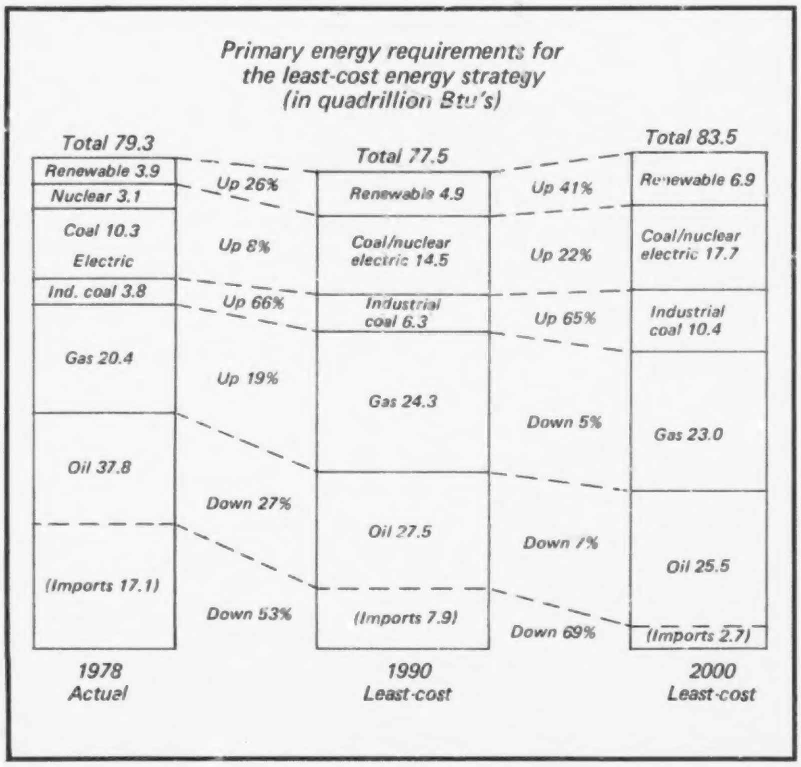
Figure 2



By shifting the focus from energy fuels to currently available “productivity (conservation and efficiency-improving) technologies” to meet human needs, researchers at the Mellon Institute's Energy Productivity Center came up with a number of startling results, some of which carry gloomy implications for the electric utility industry. For example, it is currently believed that the only way out of utility financial difficulties is through meaningful rate relief. Yet, according to Dennis W. Bakke, deputy director of the center, that organization's findings do not support this idea. “The reason (electric utilities experience financial difficulties) is that the product itself is in trouble,” Bakke told *EL&P*. “Price increases have made it less competitive than it has been in the past.”

The revised Mellon study, which is said to project the least-cost fuel mix and technology investment patterns through the year 2000, shows coal and nulcear generated electricity will rise only about one-half as fast as growth figures put out by the government's Energy Information Administration (EIA) suggest (see Figure 1). While the Mellon study emphasizes that these projections are not forecasts of what will happen, they are said to demonstrate what is possible “if known energy technology is applied on the basis of economic self-interest.”

Figure 3



Industrial co-generation is seen as being responsible for dampening centrally-generated electricity from now until the year 2000. “There are thousands of co-generation studies going on in industry today,” Bakke said. “I would bet my money that industry will follow economic arguments.” He added, “We will find ways to make this happen. This is the message to central station electricity generators.”

> ***“To say you can solve . . . utilities' problems by raising rates is much like saying we could solve the problems of Chrysler by raising the price of their automobiles.”***

There appears to be other areas where electricity is not competing very well, Bakke said. Lighting is one such area. Acknowledging that lighting did not constitute a large electric market, Bakke nonetheless noted that technological advances here, which now provide lighting with a fraction of the electricity previously needed, have been dramatic. “The market share of electricity is being taken by the light bulb manufacturers,” he said.

As shown in Figure 4, delivered energy demand for electricity produced at central stations (exclusive of station generation losses) is almost flat through the 1980's (down about 6 percent over the period) and then increases by about 1.0 percent per year during the 1990's. Coal and nuclear are assumed to be replacing oil and gas as power sources in central station generation at the same rates projected by the EIA. *Total* electricity growth, including both centralized and decentralized generation, amounts to 0.8 percent in the 1980's (the 6 percent decline in central station output being more than offset by contributions from co-generation) and 1.3 percent in the 1990's (the 0.3 percent here coming from co-generation).

Industrial demand and co-generation

The Mellon study found that under least-cost conditions, industrial energy use would continue to increase during the century. However, during the 1980's industrial consumption from the grid is down 15 percent due to co-generation. But the use of central station electricity resumes its growth in the 1990's, and on a net basis, returns to 1978 levels by the year 2000. This is because all cost-effective retrofitting of buildings has taken place by 1990, and from this time until the end of the century economic growth is reflected in increased electricity use in the building and industrial sectors. The study determined that if rational economics were closely followed, entirely new industrial facilities with different energy use characteristics would be constructed during the rest of the century.

In addition, the increased purchase of coal consumption equipment for industrial sites would become a trend in energy technology markets. These would include low Btu gasifiers, atmospheric fluidized bed boilers, and high efficiency conventional boilers. Another major trend envisioned by Mellon researchers is the installation of co-generation units at new sites of major steam-consuming industrial firms. “The most competitive co-generation system is a gas-fired turbine that generates electricity and then uses waste heat from the turbine to make steam,” the report concludes.

Utility monopoly status: A myth?

Employing economic arguments in its effort to debunk accepted maxims such as “energy is scarce,” “energy costs will increase,” “environmentalists are causing the problem,” and “conservation inhibits economic growth,” the Mellon researchers finally confront the “myth” that the generation of electricity is a natural monopoly.

“As a nation, it is important to recognize that the generation of electricity is not a natural monopoly,” the Mellon researchers proclaim.

Returning to the notion that centrally generated electricity at current prices is already uncompetitive in several energy service markets, the Mellon investigators contend that rising prices, implemented by electric utilities to alleviate financial distress, will simply exacerbate the problem. “To say you can solve utilities' problems by raising rates is much like saying we could solve the problems of Chrysler by raising the price of their automobiles,” Bakke said.

Without institutional changes, electricity is also at a significant competitive disadvantage with co-generation and other non-centralized sources of electric generation, the study maintains. Yet, it is believed that the market for electricity production is potentially as competitive as oil and gas production. Noting that there is already competition between coal, nuclear power, and hydro power for generation, it is considered critical that unconventional renewable sources of electricity be allowed to compete with more conventional ones. Thus, serious consideration should be given to separating generation from the distribution of electricity.

Continued on page 6

Advertiser and advertising agency assume liability for all contents (including text representation and illustrations) of advertisements printed, and also assume responsibility for any claims arising therefrom made against the publisher. It is the advertiser's or agency's responsibility to obtain appropriate releases on any items or individuals pictured in the advertisement.

ELECTRIC LIGHT & POWER (USPS 858-860) is published monthly. Copyright 1981, by Technical Publishing, a company of the Dun & Bradstreet Corporation—all rights reserved. James B. Tafel, Chairman; John K. Abely, President; Robert L. Dickson, Executive Vice President; John R. Emery, Senior Vice President; Robert J. (Duke) Kiesel, Publisher, Editorial and Executives offices: 1301 S. Grove Ave., Barrington, IL 60010. Phone (312) 381-1840. Distributed by controlled circulation to executives and engineers in U.S. electric utilities and consulting engineering firms. To all others there is a subscription charge of $34 per year (U.S.) $40 (Canada); and £36 foreign, £62 foreign air mail). Sole agent for all subscriptions outside the U.S.A. and Canada is J.B. Tratsart Ltd., 154a Greenford Road, Harrow, Middlesex HA 13QT. England. Single copy prices $3.00 (U.S.) $4.00 (Canada); and £4 (Foreign); Second-class postage paid at Barrington, IL 60010 and at additional mailing office. Postmaster: Send form 3579 to ELECTRIC LIGHT & POWER, 1301 S. Grove Ave., Barrington IL 60010

TMI cleanup . . .
from page 1

According to a spokesman in the Office of Management and Budget, federal funding will be from $110 to $120 million over a period of four years. This includes the approximately $37 million that has already been earmarked in FY 1982 for cleanup research and development activities in the budget of the Department of Energy.

Asked about previous declarations by Stockman that the administration would limit its role to certain R&D activities, the OMB spokesman conceded that the present announcement represented "a change in that earlier position" (see *EL&P*, July, 1981, page 2).

Asked what had prompted the change, the OMB spokesman said "the pressure was very strong from all parties concerned, including Pennsylvania Governor Thornburgh."

Governor Thornburgh had earlier outlined a proposal whereby 25 percent of the cleanup money would come from the nuclear industry, 25 percent from the federal government, and the remaining 50 percent to be shared among regional sources, including General Public Utilities, the Commonwealth of Pennsylvania, and the state of New Jersey (see *EL&P*, September, 1981, page 2).

The federal government's proposal to come up with over $100 million over four years, while substantial, falls short of the amount described in Thornburgh's shared cost approach. Said the governor, "It would be mistake at this point to assume that the full $190 million in federal funds I suggested as appropriate will be committed. It is very encouraging, however, to learn first hand that the President recognizes that this nation come to grips with the legacy of contamination of TMI if confidence in the nuclear option is to be maintained."

Final details of the arrangement were to be included in a letter to the governor from either White House counselor Ed Meese or DOE Secretary James Edwards. A spokesman for the governor's office said that the letter could be received as early as October 17.

GPU credit . . .
from page 5

receivable, the current value of its uranium supply (about $20 million), and 50 percent of Met Ed's coal supply not to exceed $5 million. The borrowing limit will decrease monthly beginning April 30, 1982 until it reaches zero on December 31, 1982. This arrangement is contingent upon the company being able to maintain adequate rates, Kuhns said.

GPU notes that if Met Ed's rates are "not adequate," the banks have said they will impose a modified paydown schedule which would require that all outstanding loans be repaid by the end of 1981. Also, the banks reportedly said they will not advance funds for the utility to make its April tax payment if rates are inadequate.

Also under the new agreement, Penelec will have a maximum borrowing limit of $75 million or $50 million plus an amount equal to its deferred energy balance (about $20 million in August), whichever is less. And Jersey Central has been given a maximum borrowing limit of $125 million, or $60 million plus an amount equal to its deferred energy balance (about $78 million in August), whichever is less.

While the sum of these sublimits is greater than the allowed borrowing maximum, it is the aggregate maximum that governs. Once the interim ceiling is reached, further borrowing is prohibited even if one or more of the operating companies has not reached its individual sublimit.

Borrowing limits

Finally, GPU—a borrowing entity in itself—is limited by its outstanding bank debt on October 1, 1981. On September 18 this was $37 million, a spokesman for the company said.

Commenting on the new borrowing maximum set for Jersey Central Power & Light, New Jersey Board of Public Utilities president George Barbour said, "With a continued weak cash position, the company has no choice but to agree to the terms set by the banks. The alternative would be to arrange a series of short-term loans at higher interest rates than they are currently being offered, if any other bank is in fact willing to loan money."

Deregulation . . .
from page 3

"Without minimizing the practical difficulties of accomplishing such a major institutional change, we conclude that the possible economic benefits of increased competition in this sector warrant widespread experimentation with—and feasibility studies of—utility deregulation," the Mellon researchers contend. In short, kilowatt hours may have to be produced and priced by competitive power generation entrepreneurs in order to find buyers in a market where least-cost principles prevail.

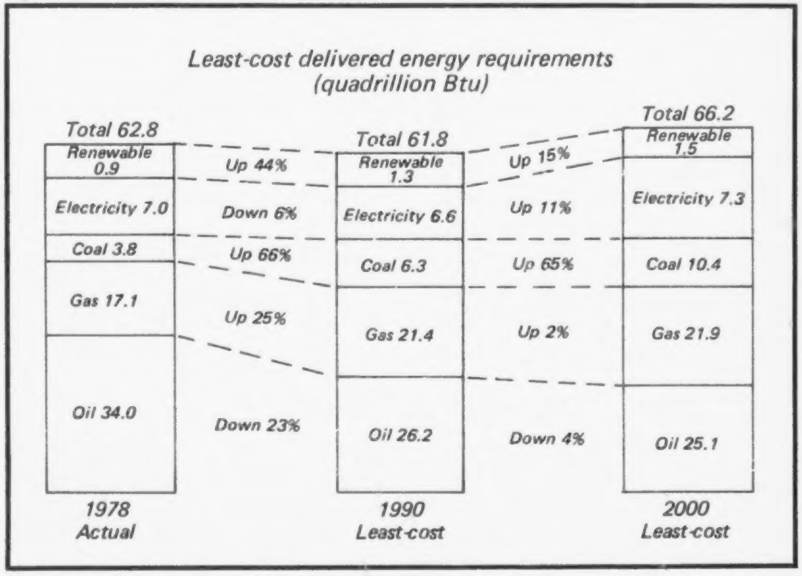
The Mellon energy study was directed by former Ford Administration conservation head Roger W. Sant who is now director of the Energy Productivity Center. He was aided by Bakke, Steven C. Carhart, and Shirish S. Mulherkar. The myths outlined in the study are said to be responsible for "our collective national ineffectiveness" in the energy area. Sant concedes that when he was with the Ford Administration he was responsible, as were others, for actually perpetuating some of these energy illusions. The present effort is an attempt to undo some of these conventions.

But while the Mellon emphasis on economics may conjure up images of budget director David Stockman at work, Institute researchers hesitate to draw an equivalence. "Our greatest disappointment will come if the Reagan Administration's "new beginning" of free market rhetoric on energy is accompanied by policies amounting merely to a scarcity-motivated government subsidization of a new set of preconceived pet solutions — which in (the Administration's) case seem to be nuclear power and accelerated fossil fuel production," Mellon researchers say.

Just how much economic factors will determine the future selection of energy supply and demand remains to be seen. Conducting an analysis and publishing results based on economic arguments alone has its risks, Mellon researcher Bakke admits. But he notes that no area of social concern has yet been identified that would invalidate the use of this economic rationale. Given current environmental constraints, for example, the least-cost strategy still works, he says.

"Markets do not work very well in a condition of scarcity," the Mellon study concludes. "In a condition of abundance, government intervention does not work at all. In the broader context of energy services, abundance appears to be our condition. Our analysis suggests that we give the economic paradigm of energy a wholehearted try. It would be the first time in a long, long time."

Figure 4

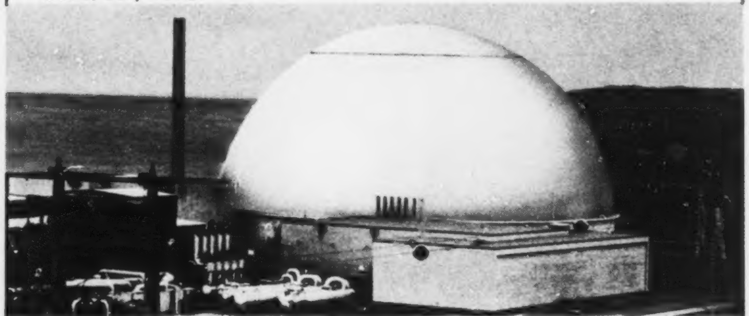


A Fast Way to Solve Condenser Air and Water In-Leakage Problems

If you have air or water in-leakage problems, call SAI for assistance. SAI will respond to your call within 24 hours with experienced personnel certifified under ANSI non-destructive testing standards. SAI has provided leak detection services to over 50 utilities in this country and abroad. The SAI Gaseous Tracer Leak Detection Technique has been proven to be......

- Fast and safe
- Performed with plant on-line
- Performed at BWR's with Radiation Exposures ALARA
- Sensitive to leaks where other methods fail:
  - Air In-Leakage - 3×10^{-4} CFM
  - Water In-Leakage - 2×10^{-5} GPM

Additional applications of the SAI Gaseous Tracer Leak Detection Technique include assisting you in meeting requirements of NUREG-0578, July 1979.



For Further Information, contact:
Science Applications, Inc. • Utility Services Division
3 Choke Cherry Road • Rockville, MD 20850 • (301) 977-4480

EL&P is looking for a new editor

Could YOU be the person we're seeking?

Electric Light & Power is looking for a strong communicator to add to its editorial staff. Successful applicant will join EL&P's aggressive editorial team in covering developments within and affecting the electric utility industry. Moderate travel required.

Applicants must possess strong writing/editing skills. Ability to understand and communicate difficult technical subjects is a must. Experience in electric utility system operations or engineering a strong plus but not imperative.

Location in EL&P's suburban-Chicago offices. Full program of company benefits.

Write: Editor, Electric Light & Power, 1301 S. Grove Ave., Barrington, IL 60010. Include resume and give salary requirements.

An equal opportunity employer

Regenerative SO_2 scrubbers look better as sulfur prices rise, market tightens

Sulfur and Sulfuric Acid Recovery at Coal-Fired Power Plants

	Operating	Under Construction	Contracted or Planned	Total
Plants with sulfur, H_2SO_4 recovery	8 units, 1599 MW	5 units, 1358 MW	0	13 units, 2957 MW
Plants with SO_2 scrubbers	84 units, 28,214 MW	34 units, 14,285 MW	65 units, 35,775 MW	183 units, 78,274 MW
Percent with sulfur or acid recovery (MW basis)	6%	10%	0	4%

(Total includes three new lime scrubbers designed to produce gypsum for sale. Rest are throwaway sludge type units. Total does not include 40 planned scrubbers for which the process has not been chosen yet.)

Source: "EPA Utility FGD Survey" January, 1981. PEDCo Environmental, Inc.

The economics of sulfur dioxide scrubbers are tipping more in favor of regenerative systems that produce by-product sulfur or sulfuric acid rather than the throwaway, sludge-type systems that most utilities have chosen so far. Sulfur prices have skyrocketed in recent years, from about $65 a ton in 1978 to about $148 a ton now.

Spokesmen for chemical and fertilizer industries are urging electric utilities that face a scrubber decision in future years to investigate the potential for the regenerative type. They've seen other U.S. sources of supply appear to peak out while foreign sources such as Poland and Iraq have proven unreliable. With prices rising and supply getting tight, and likely to remain that way for years to come, they'd love to see electric utilities become a siginifcant source of supply.

"We're certainly interested in new sources of sulfur," says Tony Longhini, director of purchasing for International Minerals and Chemicals, a major fertilizer producer (and, therefore, sulfur consumer), "and the long-term trend is for continuing tight supply unless we get some significant amounts from the utility industry." He notes one projection that sees sulfur prices climbing to $200 a ton by 1985, although he says he feels that's "on the high side." Longhini says, however, that he "certainly" sees higher sulfur prices in this decade. He says the fertilizer market consumes half the sulfur in the U.S. and can be volatile from year to year. Long-term, the purchasing official sees the demand for sulfur growing from three to five percent per year.

Another fertilizer industry spokesman, Dr. John Douglas, assistant to the manager of TVA's National Fertilizer Development Center is cautious about predicting the future, but says, "I expect the sulfur supply-demand situation in the world to remain tightly balanced for the rest of this decade." He doesn't see any significant supply from power plant scrubbers prior to 1990. Douglas notes that TVA's fertilizer development center is completely independent from the agency's power generation division. TVA has purchased scrubbers for four large power plants totaling 2500 MW, but none of the scrubbers are regenerative.

In the past couple of years, Douglas notes, there's been a change in the sulfur market situation, due to an increase in demand and a decrease in supply. He says that half a million tons of sulfur have been removed from the normal annual supply because of the Iran-Iraq war which interrupted shipments from Iraq. Poland, he reported, has also cut shipments. "We don't know why," says Douglas, but he speculates that Poland has diverted sulfur from the world market to the Soviet Union.

As a result, Douglas says that sulfur inventories in the U.S. are down from a normal level of six million tons a few years ago to three million tons of sulfur currently. With users out-consuming the supply even at today's depressed economic conditions, Douglas says, "There's no way we'll be able to keep up without pulling down inventories again."

Another sulfur market observer, John Shelton, a specialist with the U.S. Bureau of Mines, won't be pinned down to any predictions about the future for sulfur supply or prices. He notes that the market has a history of up-and-down cycles and he feels that the sulfur price may have reached a peak, for the moment at least.

Shelton agrees that events in Poland and Iraq have reduced world supply from what it could otherwise be expected to be. He adds that two major domestic sources of sulfur have either flattened or decreased in recent years. They are the "Frasch" process, which is a highly energy-intensive underground mining method, and "recovered" sulfur which comes from petroleum industry processing of "sour" natural gas and crude oil.

Demand for elemental sulfur by U.S. agriculture and industry — which is being met — is 11.6 million tons right now, says Shelton. The Bureau of Mines projection for the year 2000 shows supply, and demand, more than doubling — to 24.5 million tons of sulfur a year. Shelton sees the following sources of supply in the year 2000:

- Frasch process mining will provide 2.5 million tons a year, down from the current 6.4 million tons,
- Sulfur recovered from petroleum refining and natural gas processing is expected to rise to 14 million tons, six million from petroleum and eight from natural gas. Currently, gas processing provides 1.7 million tons and petroleum refineries produce 3.2 million tons:
- Coal gasification plants are predicted to produce two million tons per year, via recovery from the hydrogen sulfide gas that must be removed from coal gas. That source is now zero,
- Coal-burning power plants are expected to provide three million tons of sulfur a year, up from a very small amount currently,
- By-product sulfuric acid production from non-ferrous metal production is predicted to rise from one million tons of sulfur (equivalent) now to 2.5 million tons, and
- Sulfur recovery from pyrites removed in copper and molybdenum mining should reach half a million tons by the year 2000.

Shelton notes that only two electric utilities, Northern Indiana Public Service Co. and Public Service Co. of New Mexico, are reporting commercial production of sulfur to the U.S. Bureau of Mines.

For utilities evaluating future scrubber designs, Shelton notes there are three options: the throwaway type, the acid-recovery type, and the sulfur type.

The cheapest and easiest option is the throwaway sludge type, "as long as disposal continues to be environmentally acceptable," says Shelton. If a utility decides to go with a regenerative type scrubber, it must decide to recover the sulfur values in the form of elemental sulfur or sulfuric acid.

The acid option is cheaper, says the Bureau of Mines official but presents a storage problem. There will generally be a limited amount of storage capacity for the highly corrosive, concentrated acid at a production facility — it can't just be dumped on the ground as can elemental sulfur. Therefore, if product can't be shipped, and storage is filled, the plant must be shut down.

Elemental sulfur recovery is much less market sensitive because it can be piled up, within limits, at a relatively minimal cost. However, most of the sulfur that's used in the U.S. is used in the form of sulfuric acid, says Shelton.

A recent study done by Stearns-Roger Engineering Corp. for EPRI confirms Shelton's estimate of relative costs. According to the study the capital cost of a Wellman-Lord scrubber system with an acid plant is $265 a kW; with a sulfur plant the cost is $245 per kW. The comparable capital cost of a limestone scrubber is $185 per kW. The levelized busbar cost of each option, based on by-product credits of $50 a ton for sulfur and $40 a ton for acid, in mills per kWhr, are: 15.7 for the acid option 19.0 for the sulfur option, and 12.9 for the limestone scrubber.

As shown in the table regenerative scrubbing has not been popular with utilities. Only six percent of the operating scrubbers and 10 percent of those under construction produce a sulfur or sulfuric acid by-product. Looking further into the future, none of 65 scrubbers being planned for power plants not yet under construction will produce a by-product.

As can be seen in the list of operating regenerative systems and those under construction, the leading supplier is Davy-McKee Co. of Lakeland, Florida which supplies the Wellman-Lord process. Davy-McKee had the first commercial regenerative system, which was installed at Northern Indiana Public Service Co.'s Mitchell plant in 1977. The company also had the first large installation with all four units of Public Service of New Mexico's San Juan station, totaling nearly 1800 MW.

The NIPSCO scrubber/sulfur recovery unit was retrofitted on to a 115-MW unit that burns three-percent sulfur Indiana coal. According to report at the last EPA FGD symposium, the scrubbing system was able to achieve a 90 percent sulfur removal rate at a plant output of 85 MW, but system reliability was about 75 percent due to startup and debugging problems. The paper, given by the utility's E.L. Mann and TRW's R.C. Adams, reported that during the operating period January 1, 1979 through April 30, 1980 the total FGD system operating and maintenance costs were $6.2 million and the sulfur by-product credit was $105,000. During that period the generating unit burned 349,000 tons of coal with an average sulfur content of 2.85 percent. The utility sold 2,668 tons of elemental sulfur locally.

Davy-McKee also supplied the system at Public Service of New Mexico's San Juan station. Scrubbers and a sulfur recovery system were retrofitted to three existing units — Nos. 1 and 2 are 350 MW each and No. 3 is 500 MW — about a year ago. Unit 4, a new 500 MW unit, is scheduled to start in about a year and will also be covered by the scrubber/recovery system. The units all burn a coal with a heat value of 10,000 to 11,000 Btu per lb and a sulfur content of 0.9 percent.

The scrubber/recovery system has been running at an excellent availability of 95 percent, with sulfur removal running in the 70 to 80 percent range, reports chemical plant superintendent, Jim Petrie.

He reports that the utility hired Davy-McKee to install an acid plant at the station which is slated to be in operation next year, taking care of the sulfur dioxide removed from all four units. They decided to switch from sulfur to acid because sulfur recovery required a high level of ener-

continued on page 68

Repower oil, gas-fired plants with coal-fired combined cycle

R.V. Garland
Westinghouse

Repowering modern, reheat oil- or gas-fired power plants with coal and combustion turbines is a viable alternative to adding new plants. It can add capacity while reducing, and in some cases eliminating, the use of oil or gas. A combined cycle repowered plant can improve plant heat rates as much as 12 percent, and can almost double the output for a given site depending upon the particular repowering configuration.

In the past, repowering usually involved fully depreciated non-reheat steam cycles of relatively small capacity. The existing boiler and fan systems were replaced by the combustion turbine and a supplemental boiler. These combined cycle systems included unfired and fired supplemental boilers. The steam boilers were old, and relatively small financial risks were involved. Repowered systems improved plant efficiency in the order of 10 to 20 percent and increased plant capacity as much as 100 percent, but repowering was not widely used because of the relatively small size of the total repowered system.

Much larger blocks of power are effected by repowering a modern reheat plant and the resulting gains are much more attractive. A typical reheat oil and/or natural gas fired unit with regenerative feedwater heating, less than 20 years old, will be examined. Figure 1 is a schematic representation of such a plant. There are several configurations that can be applied to repower such a plant. They convert the existing, conventional electric generating plant into a combined cycle by integrating one or more combustion turbines.

A previous analysis conducted for the Electric Power Research Institute (EPRI) has shown that the most versatile and efficient repowering configuration with the greatest potential for increased power is the supplemental boiler repowering scheme. It uses a supplementary boiler between the combustion turbine exhaust and the main boiler. (See Figure 2.) By cooling the gas to material temperature limits and producing steam in the process the existing boiler windbox can be retained. Depending upon the particular example, the supplemental boiler can help the main boiler generate and partially superheat throttle steam, or it can generate steam for the gasification system in those cases where gasification is applicable.

Exhaust gases enter the boiler windbox at about 700F so the air preheater can be eliminated. This allows the boiler exit gases to heat feedwater in a stack gas cooler.

The stack gas cooler permits splitting the feedwater stream in a strategic location, allowing a portion of the water to be heated in the stack gas cooler and the remaining portion to be heated in existing feedwater heaters. The streams then join just before they enter the main boiler economizer and the flow rate is maintained at original conditions. Since the flow through the high pressure feedwater heaters is reduced, the extraction steam quantities also diminish, thus increasing the power output of the steam turbine.

The remaining discussion of combustion turbine repowering of reheat steam power plants will cover four types of coal utilization techniques: coal derived liquids (CDL), coal derived gases (CDG), direct coal burning in an atmospheric fluid bed (AFB), and direct coal burning in a pressurized fluid bed (PFB).

To gain a meaningful impression of how repowering with coal affects plant performance, it is necessary to choose a candidate plant. Westinghouse has performed considerable study work on repowering for EPRI, applying a typical 333-MW reheat plant whose steam conditions are 2400 psig/1050F/1000F/1.5 in HgA. It is fired by oil or natural gas. The plant net heat rate is 8960 Btu/kWh (HHV) fired on a low sulfur residual oil. Item 1 of Table 1 lists its performance.

Coal derived liquids

In this analysis, it is assumed that coal derived liquids contain at least 10 weight percent hydrogen and no more than 0.2 weight percent nitrogen. State-of-the-art combustion turbines and boilers can use this fuel.

Under the above constraints, there is little difference in plant performance when comparing CDLs to petroleum fuels. Thus, it is possible to use the coal-derived fuels in a plant configuration shown schematically on Figure 3. This is essentially the same configuration used with petroleum fuel. If two Westinghouse W501 type combustion turbines are used in the repowering scheme, one could expect the repowered plant output to be about 60 percent greater and the plant thermal efficiency (heat rate) to be about 12 percent better than the conventional reheat steam plant (See Item 2 of Table 1). The use of petroleum-based fuel is eliminated.

If the gas turbines were equipped with supercharging fans, the output increases. Adding a fan and an evaporative cooler before the conventional compressor inlet is

Table 1. Performance parameters for the various repowering options.

SUMMARY OF REPOWERED PERFORMANCE USING COAL

Item	Description	CT fuel	Boiler fuel	CT MW	Main ST MW	Gasif. ST MW	Plant aux MW	Plant net MW	Plant net hr	% MW increase	% Hr improve	% red. petro fuel	Fuel to plant boundary
1	Conventional plant		Petrol	N/A	338	N/A	5	333	8960	–	–	–	Petroleum
2	Non-integrated non-supercharged CT's	Coal liq.	Coal liq.	178	360	N/A	5	533	7900	60	12	100	Coal liquid
3	Non-integrated supercharged CT's	Coal liq.	Coal liq.	226	368	N/A	15	577	7900	73	12	100	Coal liquid
4	Non-integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	172	360	N/A	4	528	7900	58	12	100	Coalgas
5	Non-integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	209	364	N/A	15	558	7900	68	12	100	Coalgas
6	Partially integrated non-supercharged CT's	Med Btu coalgas	Petrol	170	359	100	47	582	9000	75	-0.5	9	Coal & petroleum
7	Partially integrated supercharged CT's	Med Btu coalgas	Petrol	207	363	109	64	615	9070	85	-1.5	10	Coal & petroleum
8	Fully integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	170	365	144	105	577	10360	73	-15.5	100	Coal
9	Fully integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	207	371	149	121	606	10280	82	-14.5	100	Coal
10	Atmos. fluidized bed one air turbine	Coal	Petrol	55	351	N/A	6	400	5510	20	4	16	Coal & petroleum
11	Press. fluidized bed one air turbine & one expander	Coal	Petrol	63	123	N/A	3	183	8550	–	–	30	Coal & petroleum

*Heat rate based on total fuel HHV energy delivered to the plant boundary and net kW output

**Supercharging fan and evaporative cooler not shown on figure

Table 2. The options can be compared on the basis of revenue requirements.

FUEL REVENUE REQUIREMENT FOR VARIOUS REPOWERING SCHEMES

Item*	Description	CT fuel	Boiler fuel	Heat rate	Fuel revenue requirement
1	Conventional plant	–	Petrol	8960	4.66 ¢/KWH
2	Non-integrated non-supercharged CT's	Coal liq.	Coal liq.	7900	4.11 ¢/KWH
3	Non-integrated supercharged CT's	Coal liq.	Coal liq.	7900	4.11 ¢/KWH
4	Non-integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	7900	4.11 ¢/KWH
5	Non-integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	7900	4.11 ¢/KWH
6	Partially integrated non-supercharged CT's	Med Btu coalgas	Petrol	9000	3.07 ¢/KWH
7	Partially integrated supercharged CT's	Med Btu coalgas	Petrol	9070	2.98 ¢/KWH
8	Fully integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	10360	1.55 ¢/KWH
9	Fully integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	10280	1.54 ¢/KWH
10	Atmos. fluidized bed one air turbine	Coal	Petrol	8610	3.61 ¢/KWH
11	Press. fluidized bed one air turbine & one expander	Coal	Petrol	8550	2.72 ¢/KWH

*Items are in same sequence as those in Table 1.

Remarks

1. All figures based on fuel delivered to plant boundary.
2. Fuel costs assumed
   A) Coal: \$1.50/10^6 Btu
   B) Petroleum fuel, coal liquid, coalgas; all assumed \$5.20/10^6 Btu

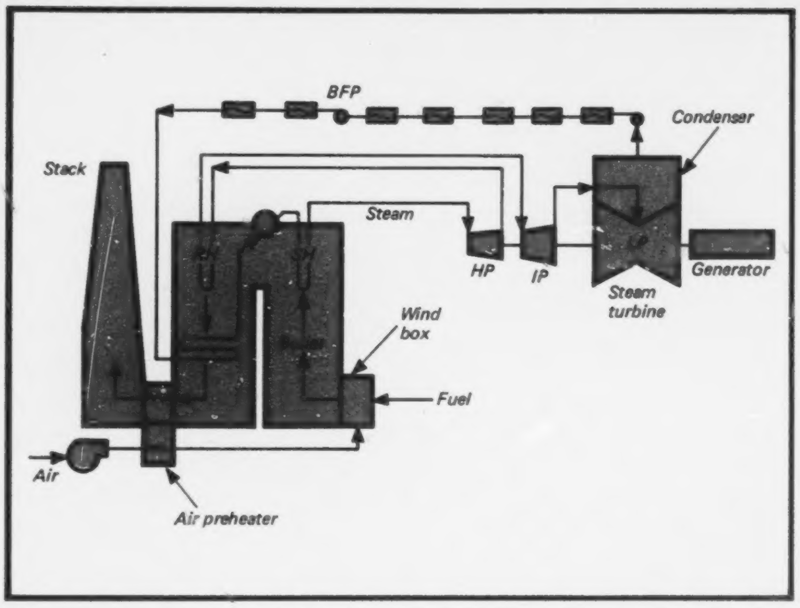


Figure 1. A good candidate for coal-fired combined cycle repowering is a typical reheat cycle with regenerative feedwater heating.

Figure 2. The reheat cycle plant can be repowered by adding a supplementary boiler and combustion turbine in front of the main boiler.

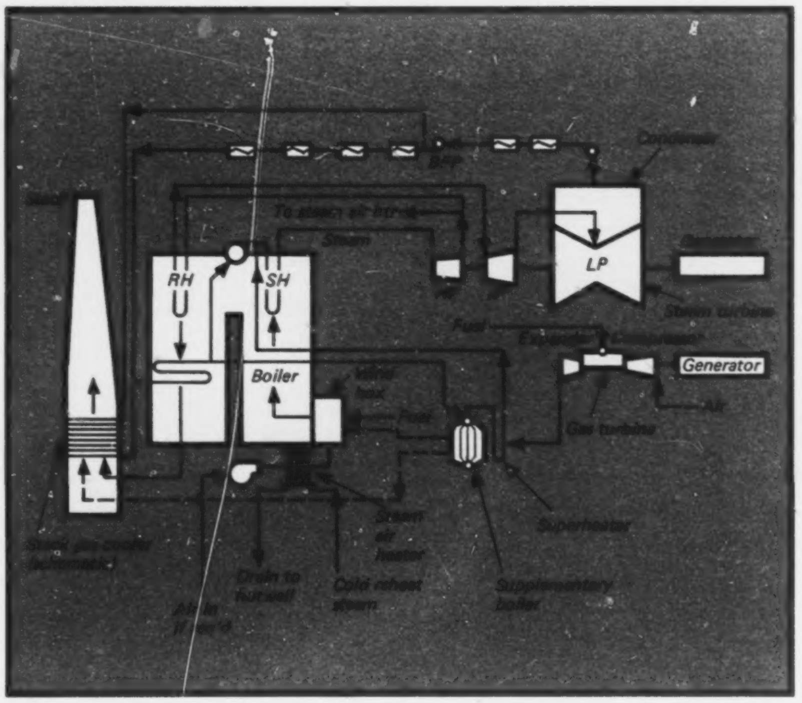
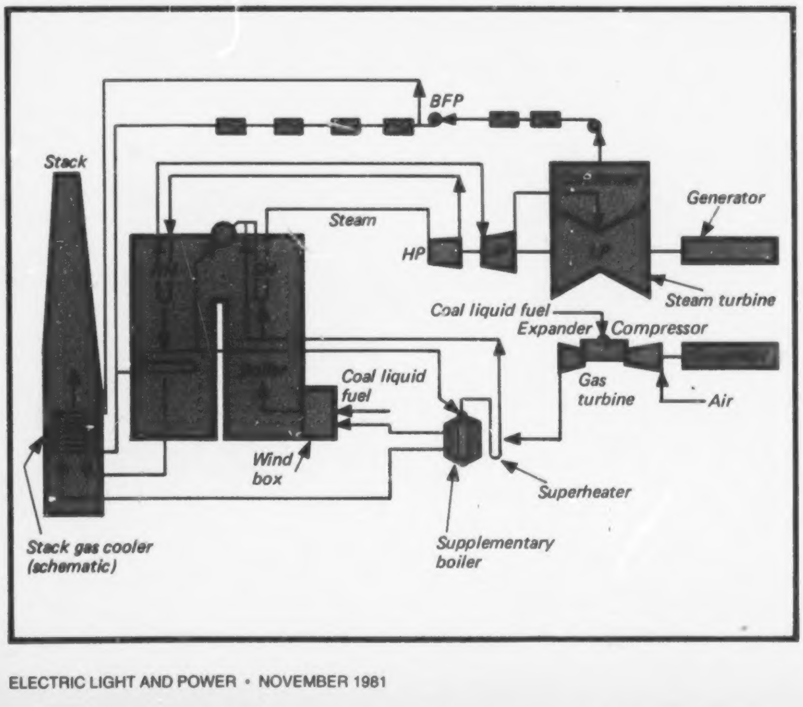


Figure 3. Repowering is possible using coal-derived fuels.



analagous to adding an additional stage with intercooling which increases the turbine mass flow and overall pressure ratio. Item 3 of Table 1 shows that repowering with two supercharged combustion turbines fired with CDL boosts the conventional plant output by 73 percent. The heat rate remains improved by 12 percent, the same as the non-supercharged case.

Plant modifications would change the existing boiler burner system; strengthen some furnace structures, alter the feed water heating system; rework the main steam turbine/generator; remove the air preheater; add a stack gas cooler for additional economizer capacity; and add hot gas ducts to the combustion turbines and the boiler. No changes require extensions beyond the state-of-the-art.

Plant emissions depend on a number of factors, including the amount of fuel-bound nitrogen and hydrogen in the fuel. The same factors must be considered for CDL fuels as is considered for the petroleum fuels. Thus, proper fuel quality will control the SOx, NOx, CO, UHC, smoke and particulate emissions. Steam or water injection to the combustion turbines is also valuable in controlling NOx.

Medium Btu coal gases, that is, coal gases manufactured from oxygen-blown gasifiers, possess gross heating values around 300 Btu/scf. These fuels contain large volume percentages of CO and H_2, typically 50 percent and 35 percent respectively. Burning these medium Btu fuels produces flame temperatures higher than normal. At normal excess air conditions, the furnace absorption tends to increase while the absorption in the convective surfaces diminishes. Medium Btu gas can be applied to repowering with combustion turbines in three ways:

1. Fuel gas supplied by pipeline from a remote source and fired in both the combustion turbines and the main boiler.
2. A partially integrated plant where the combustion turbines burn site-manufactured fuel gas while the main boiler retains oil or natural gas firing.
3. A fully integrated plant where the site-manufactured fuel gas is burned in both the turbines and the main boiler.

Schematically, there is no difference in plant configuration between the repowered plant running on a coal derived liquid and the repowered plant running on medium Btu coal gas supplied from a remote source. However, there are basic differences between the two which will be touched upon later.

When two W501 type combustion turbines, both fired on medium Btu coal gas, are applied to the repowered plant, the net plant output increases to 528 MW. The HHV heat rate, based on fuel gas supplied to the plant site at required pressure, is 7900 Btu/kWH. Thus, the power increases about 58 percent, the heat rate improves about 12 percent over the conventional plant, and no petroleum based fuel is consumed. See Item 4 of Table 1.

If the two combustion turbines are supercharged, the plant output is 558 MW; the heat rate remains about 7900/Btu/kWh. That is a 68 percent increase in output and a 12 percent improvement in heat rate. See Item 5 of Table 1.

The plant modifications required to repower on coal gas involve the same components mentioned in the coal liquid case. The boiler burner and fuel supply system require more extensive changes. Not only is the oxygen supply diminished by the vitiated air from the combustion turbines, but the fuel mass flow is about four times greater than a natural gas application.

Plant emissions do not pose serious problems regarding SOx, CO, UHC, smoke, and particulates. Increased NOx emissions are expected in the combustion turbine due to higher flame temperatures. However, steam or water injection can be used if needed. Both laboratory and field tests show that the total NOx generated by the turbine and the boiler can be reduced significantly since the turbine combustor-boiler burner repowering configuration is actually a form of staged combustion.

When the coal-derived fuel gas is manufactured on site, it is desirable to integrate the gasification system with the power generating system. Raw fuel gas is hot, as high as 2400F in some gasifiers, and it must be cooled before it can be processed to remove sulfur and particulates. Cooling the raw gas efficiently involves steam generation, feedwater heating, and clean fuel gas reheating. The additional steam generation resulting from cooling the raw gas is sent to a separate gasification system steam turbine generator.

In the partially integrated repowered system, the boiler retains oil or natural gas firing. Only the combustion turbines are coalgas fired. The main steam system is, essentially, a separate system although the combustion turbine exhaust gas is still used as a combustion air source for the main boiler. The steam generation and superheating done in the supplemental boiler is part of the gasification steam system.

The gross power output of this partially integrated scheme is 630 MW, firing two combustion turbines on coalgas and retaining low sulfur residual oil firing in the main boiler. The gasification system steam turbine, a non-reheat machine, contributes about 100 MW of the total. The auxiliary power, however, totals about 47 MW, most of which is attributable to the air separation plant compressors needed in the oxygen blown gasification system. Net output is, therefore, about 582 MW roughly 75 percent more than the conventional plant output (Item 6 of Table 1). The net heat rate is about 9000 Btu/kWH practically the same as the conventional plant heat rate, 8960 Btu/kWh.

If two supercharged combustiton turbines are applied, Item 7 of Table 1 shows the net plant output increases to 615 MW with a net heat rate of 9070 Btu/kWh. Hence, the net power increase is 85 percent and the heat rate is roughly 1.5 percent higher than the conventional plant.

A fully integrated repowered plant means that both the combustion turbines and main boiler are fired with coal gas. The plant configuration is much like the partially integrated case. The gasification system steam turbine is much larger, however, since the gasification system is larger. Gasification system steam is superheated by combustion turbine exhaust gas sensible heat in a configuration similar to the partially integrated case. Note, however, that there is no supplemental evaporator in the combustion turbine exhaust. Very great quantities of steam are generated in the gasifier gas cooler in this case. Thus, only superheating duty is required of the turbine exhaust gas energy before it is used in the main steam system.

Item 8 of Table 1 lists the performance for a non-supercharged configuration. Net output is 577 MW. The gasification system steam turbine generates 144 MW: almost 50 percent more than the similarly configured partially integrated case shown in Item 6. Note also that the plant auxiliaries in this case are more than twice as large as the Item 6 configuration. The much larger gasification system requires larger air and oxygen compressors for the air separation plant. This scheme increases the conventional output by 73 percent, but the 10,360 Btu/kWh net heat rate represents a 15.5 percent degradation in efficiency over the conventional system. The effect of the gasification plant efficiency can be quantified by comparing Items 4, 6, and 8. With coal gas supplied to the plant from a remote source, the repowered plant efficiency is 12 percent better than conventional. If the gasification plant is integrated with the powerplant, but oil firing is retained in the boiler, the repowered plant efficiency is about the same as conventional plants. With full integration, which includes coal gas firing in the main boiler, the repowered plant efficiency is about 15 percent poorer than conventional plants. However, this fully integrated example yields a net heat rate equivalent to a conventional coal fired plant with stack gas scrubbers. Of course, petroleum-based fuel use is eliminated entirely.

In the case of two supercharged turbines,

Continued on page 28

Detroit launches complex trash-to-energy system

DETROIT — City officials here announced that a huge garbage-to-energy project originally announced in 1977 is now definitely on the drawing boards. Working with Detroit Edison and Combustion Engineering, the city plans to sell $300 million worth of revenue bonds next spring to build a 3000 ton-per-day system to process and burn the city's trash. Most the the steam generated would be used in Detroit Edison's existing downtown heating system.

"The plant will be financially self supporting," said Detroit mayor Coleman Young, "with revenues generated by disposal fees paid by the city, which now go outside Detroit, and by Detroit Edison payments for the steam and electricity by-products. The substantial suburban landfill requirements of Detroit will be significantly reduced while throw-away resources within the city are recovered and constructively reused." The city generates an average of 3000 tons of trash daily. It's collected at three transfer stations and hauled to privately owned landfills outside the city.

Combustion Engineering will supply the trash processing and burning equipment, which is expected to begin operating in 1985. There will be three process streams sized so that only two are needed to yield maximum system output. The 100 ton-per-hour processing lines will be modeled after the system installed in Madison, Wisconsin, says CE manager Noel Hazzard. Each "line" will have a flail mill, a ferrous magnet system for recovering iron, a trommel screen system, and a secondary shredder for final size reduction. The system is designed to produce combustible material with a top size of six inches, with 90 percent less than four inches. The processing plant will have three of these lines.

The three processing streams will feed three CE shop-assembled spreader-stoker steam generators, that will be fueled exclusively by the refuse-derived fuel. Each boiler has a nominal capacity of 342,000 lb of steam per hour at 700F and 600 psi. The steam will be fed to an extraction turbine with a nominal capacity of 47 MW.

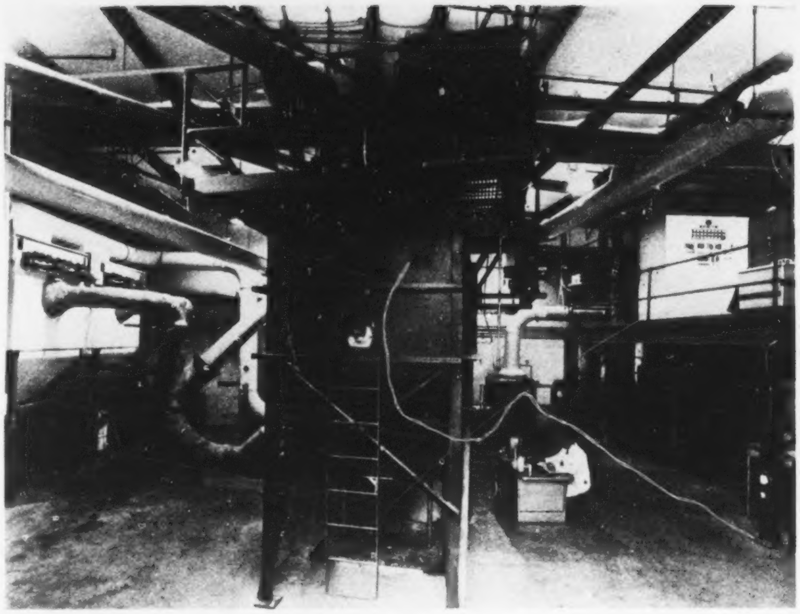
Most of the trash-energy will be used in the form of extraction steam for Detroit Edison's steam heating system. This system has 60 miles of underground main steam pipes in downtown Detroit serving about 800 customers. Originally coal-fueled, the steam generators now run largely on natural gas. The existing boilers will be replaced with the trash system.

CE's Hazzard says the system is sized so that at an average throughput rate of 3000 tons of trash a day, at average winter steam demand conditions, the system will produce 415,000 lb per hour of extraction steam at 430F and 235 psig and about four megawatts of electrical power to be sold to Detroit Edison. The steam will be produced in two boilers feeding the single turbine generator. The third processing line and boiler is redundant. The electrical output is net. At the conditions cited, the generator will produce 10.5 MW gross with 6.5 MW required for internal plant power consumption.

At the average 3000 ton-per-day throughput in periods of minimal steam demand, during spring or summer, the extraction steam will be only 200,000 lb per hour and the net electrical output will be 24 MW (30.5 MW gross.)

The turbine was sized at 47 MW, Hazzard explains, because the city and utility wanted to be able to accommodate a peak trash throughput of 4000 tons per day. They didn't want turbine-generator capacity to be a limiting factor, since there's plenty of spare capacity in the processing plant and steam generators. At that peak throughput the system could generate 557,590 lb per hour for the district heating loop, out of a total of 684,000 lb per hour from the two steam generators at turbine inlet conditions of 700F and 600 psig.

Contract negotiations among the three parties are still being finalized, Hazzard reported. He noted that CE will operate the trash processing/steam generating system, requiring a three-way deal. The city has to assure CE of a flow of trash; CE has to guarantee a supply of steam and electricity; and the utility has to agree to buy a certain amount of energy.



Radwaste facility handles 1,000 MW nuclear power plant

WINDSOR, CT — A waste incinerator designed to treat nuclear power plant liquid, slurry and dry wastes has been developed by Combustion Engineering. During prototype testing, the system handled 1,000 gallons of liquid waste, 3,200 lbs of dewatered resins and 2,200 lbs of dry combustible solids. As a result, the company feels the system is capable of handling the waste input from a 1,000 MW plant. The combustion product, ash and dry salts, can be solidified in a binding medium for final disposal. CE says the volume reduction rate varies from 50:1 to 200:1 depending on the types of combustible materials. The combustor can be seen in the center of the photo. The off-gas filtering equipment is on the left and the scrubbing hardware and control system is on the right.

Repowering . . .

from page 25

(Item 9 of Table 1), the output increases 82 percent and plant efficeincy drops 14.5 percent.

The coal fired atmospheric fluidized bed (AFB) combined cycle offers a new approach to repowering an existing plant. A coal combustor is added, replacing the conventional combustor on the combustion turbine. The AFB has both an FD and ID fan, and also uses an air preheater. The turbine receives clean air, heated in submerged tubes in the AFB, and exhausts to the main boiler at 733F. Only one non-supercharged turbine is used in this case, run on pure air at the reduced turbine inlet temperature.

No supplemental boiler is included. Instead, steam is generated in the AFB which augments production in the main boiler. All superheating is done in the main boiler superheater. Plant output increases 20 percent and the heat rate improves 4 percent over conventional operation. Most important, the use of petroleum based fuel is reduced 16 percent. See Item 10 of Table 1.

Plant emissions are environmentally acceptable. Since the AFB is maintained at 1600F, NOx is not a major problem. Limestone fed to the bed along with the coal absorbs the sulfur oxides. Particulates are controlled by a baghouse filter and cyclones.

The turbine also benefits from the low operating temperature. At 1500F, clearances and blade airfoils can be optimized for performance since cooling the various components is not as crucial as it is at conventional firing temperatures of over 2000F.

The coal fired pressurized fluidized bed (PFB) combined cycle also can be applied to repowering. This example does not utilize the 333 MW example plant; nonetheless it shows that it is possible to reduce petroleum-based fuel use up to 30 percent. (See Item 11 of Table 1.)

Table 1 shows a variety of outputs, efficiencies, and methods of repowering. To select a particular method as the best is, of course, impossible since specific economic data and the needs of individual utilities vary. However, to gain at least a measure of comparison among the various schemes, Table 2 presents the fuel revenue requirement based on some assumed fuel costs. EPRI's Technical Assessment Guide indicates that a representative cost for coal is $1.50 per million Btu; for a refined coal liquid, $5.20 per million Btu. If an acceptable petroleum-based fuel and a medium-Btu coal gas can be delivered at the same price as the coal liquid, the fuel revenue requirements for the various repowering schemes are as shown on the table.

The tabulation is not intended to reveal any clear advantage of one repowering method over another. It displays only one measure for comparison, the fuel revenue requirement. Configurations which receive coal at the plant boundary show lower fuel revenue requirements. The fully integrated examples yield the lowest figures. Even though the heat rates for Items 8 and 9 are the highest, they use 100 percent coal and manufacture the fuel gas on-site, with a revenue requirement of about 1.55 cents per kWh. However, these configurations are more complicated because the gasification system is integrated with the power plant. The table shows that, regardless of the fuel option and configuration chosen, revenue requirement is lower after repowering.

Modified scrubber . . .

. continued from page 26

sumption in the system.)

As shown in Figure 2 (both figures are taken from an unpublished APS paper) sulfur removal efficiency increased to an impressively high level as pH increased, getting above 90 percent when magnesium lime was used. That could have been predicted. What was not expected, however, was that the system became subsaturated with respect to calcium sulfate at the elevated pH level, Bill Nelms explains. The signficance of that is there was no gypsum scaling. In fact, at subsaturated conditions, the system became, as he puts it, "self cleaning."

APS's Jarman explains that a key to the success of the system is the low level of oxidation in the system — that is, the relatively high level of calcium sulfite to calcium sulfate. The question became: what happened to the calcium sulfate?

Unexplained phenomenon

What was occurring, says Nelm, was the "unexplained phenomenon" of "nucleation" of the calcium sulfates and sulfites on flyash particles. Evidence of this effect could also be seen in the relative absence of sulfites and sulfates in the bleed from the thickener, says Nelms. He says that the nucleation effect can be seen in the reproduction of the electron micrograph. The large sphere in the photo (magnified 10,000 times) is a flyash particle taken from the thickener underflow. The slivers attached to the surface of the particle are calcium sulfites, says Nelms, and the plates are sulfates.

The nucleation effect explains why the test showed sulfur removal rates as 90 percent at a non-corrosive pH of 6 to 8 with no gypsum scaling, adds the engineer. The test even showed that the venturi pressure drop could be reduced from 21 in. of water down to t 6 inches with no loss of emission control. While all this was happening, Nelms points out, particulate emissions remained in compliance.

All six scrubber modules were modified, at a cost of only $15 million, says Nelms. Much of the capital expense was for a lime slaking system (described in *EL&P* December, 1980, page 46.) Since the modified scrubbers started operating in 1979, they have met the emission standards and have not been hobbled by corrosion and scaling.

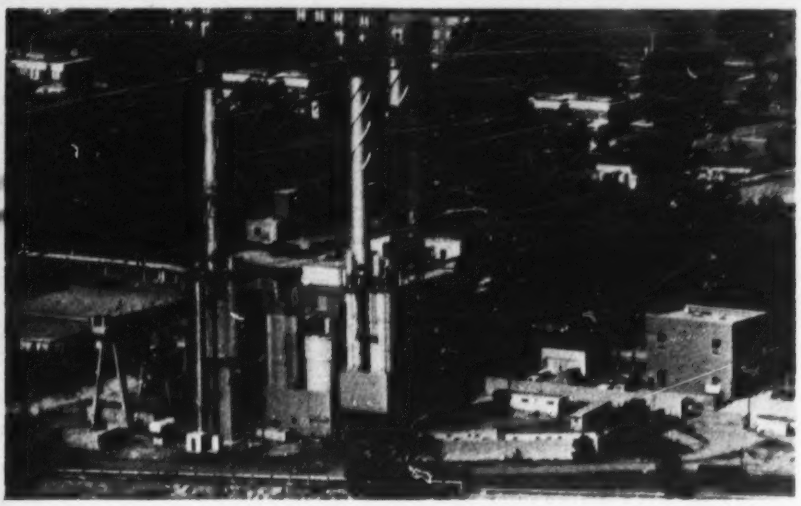
The venturi scrubber technology was not used on Four Corners units 4 and 5. These two units, 800 MW each, were built in 1969 and 1970 and were equipped with cold side electrostatic precipitators. Faced with stricter particulate and sulfur dioxide emission limits, APS decided to add wet lime spray towers for SO_2 and bag filters for the particulates. Total cost of the new system is estimated at $500 million. The spray tower will be designed to meet a 72 percent SO_2 removal rate. It will treat 80 percent of the gas flow from the two units with 20 percent used for flue gas reheat.

Why not a single-stage venturi? APS executive Jarman explains that all the results on the operations at units 1-3 were not in yet when the decisions were made for units 4 and 5. He also feels that the venturi technology is probably limited to retrofits.

Nelms, however, is looking for applications on new power plants. He hasn't interested a manufacturer in licensing his technology yet, but he's trying. He estimates that the simplified venturi for both particulate and sulfur dioxide scrubber is at least 30 percent cheaper than other wet scrubbing alternatives. Now operating a consulting business in Scottsdale, Arizona, Nelms feels it's just a matter of time before the technology catches on.

Process co-inventor Charles Turton, who still works as an engineer with Arizona Public Service says that he feels the process makes wet scrubbing "cost competitive" with dry scrubbing for low sulfur coal. However, the process is not limited to low-sulfur coal applications, in his opinion. He refers to laboratory work which shows that the coprecipitation phenomenon occurs on high sulfur coal type flue gases. Turton says that none of the existing scrubber manufacturers have shown much interest in the process yet, but some other companies have.

Fluid-bed demo starts up at Great Lakes Naval Station



A fluid bed steam generator installed at the U.S. Navy's training center on Lake Michigan consumes 27 tons of high-sulfur Illinois bituminous coal per hour.

GREAT LAKES, IL — A coal-fired fluidized bed combustion demonstration plant has started up at the U.S. Navy's Great Lakes Training Station here, announced boiler supplier, Combustion Engineering. Operation of the 50,000 lb/hr steam generator is the culmination of a $23 million program sponsored since 1976 by the U.S. Dept. of Energy.

Fueled by Illinois No. 6 coal — 3.5 percent sulfur and 10 percent ash — the fluid bed boiler is designed to provide steam at 365 psig and 560F for building heating. This is the second of the "big" fluid bed steam generation demonstrations sponsored by DOE. The first was a 100,000 lb per hour unit built by Foster Wheeler for Georgetown University's heating system in 1979.

Atmospheric pressure

The CE unit at Great Lakes is designed to operate at atmospheric pressure and a bed temperature of 1500 to 1600F, a temperature below the ash fusion point and low enough to keep nitrogen oxide emissions at an estimated level of 0.4 lb per million Btu (less than the federal standard for coal-fired power plants.) The system uses crushed limestone in the bed to capture sulfur dioxide in the flue gas right in the furnace. At a calcium-to-sulfur ratio of three to one over the operating temperature range, the system should capture 90 percent of SO_2, says CE.

Emissions

Particulate emission from the boiler is controlled in a mechanical separator and a bag filter at the back end of the process. With an inlet grain loading of 4.6 gr per scf the design outlet is 0.03 gr per scf, says CE project manager, Bill Norcross.

Norcross says that $23 million project cost covers everything spent since 1976, including a sub-scale process unit at CE's research laboratory in Connecticut. The cost of hardware at the Great Lakes facility is only $8 million, he adds, and that includes test equipment that would not be necessary in a commercial installation.

Prototype

CE says that the Great Lakes installation is the prototype for shop-assembled fluid bed systems capable of producing up to 200,000 lb per hour of steam. Norcross points out that this design is intended for industrial applications. The company is developing a design strictly for utility applications. CE says that fluid bed combustors may offer advantages over conventional coal-fired boilers because they eliminate the need for back-end sulfur scrubbers and they can accommodate a wider range of coal types.

Sulfur . . .

from page 21

gy consumption in the form of natural gas. Acid production, says Petrie, should be more cost-effective.

P.S. New Mexico wholesales its sulfur products to Phillips Petroleum Co. of Bartlesville, Oklahoma on a long-term contract basis. The arrangement is "working very well," says Petrie. He sees no problem in selling acid through Phillips. The plant's nominal capacity is 470 tons of acid per day which, according to the manager, is small as sulfuric acid plants go.

Petrie feels the long-term market outlook for by-product sale is good. "We don't look for any problems in marketing either sulfur or acid," he says.

Acid plant

The other large installation is currently under construction at Philadelphia Electric, where a regenerative acid system designed by United Engineers is being retrofitted to three generating units totaling 900 MW. The scrubbers will produce a dry sludge which will be trucked to acid plants operated by Allied Chemical Co. in Claymont, Del. and Essex Chemical Co. in Newark, N.J. The utility is putting up all the capital for the project, $312 million, and the chemical companies will operate the regeneration/acid production facilities. Operation is scheduled for 1983.

And, based on plans announced to date, that will be the last regenerative scrubber installed on a U.S. power plant, despite the improved economics.

Congratulations
to Atlantic (City)
Electric

Selected
the Electric Utility
of the Year 1981

By Electric Light &
Power Magazine

No matter how the world
solves its energy problems,
McDermott is involved.

Bailey® Controls

©1981 Babcock & Wilcox

Babcock & Wilcox, a McDermott company

Inquire R.S. 35

0912 14 1825157 11 ■50 1
COPY TWO
STATISTICAL REFERENCE
4520 EAST-WEST HWY/STE
WASHINGTON DC 20014

/C 8650 - 4

Volume 59, Number 12
December 1981

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Initiative 394 passes; Washington state voters now control funding for nuclear construction

Dan Utroska
Associate Editor

OLYMPIA, WA— The Washington State initiative requiring the Washington Public Power Supply System to secure voter approval before selling additional bonds for power plant construction has passed by a vote of 58 percent.

While the effect of Initiative 394 will definitely impact the supply system's ability to finance further nuclear power plant construction, the announced construction slowdown of units 4 and 5 will mitigate the impact somewhat. Bond sales for these plants will not be necessary until at least July, 1983, a spokesman for the supply system said.

On the other hand, planned bond sales to finance units 1, 2, and 3 will definitely collide with implementation of the initiative, which is scheduled to become effective in July, 1982. WPPSS has typically sold bonds about every 6 months, and the utility may go out for one sale—or possibly two—before the initiative is imposed.

'Don't Bankrupt Washington'

The initiative originated in a state organization called Don't Bankrupt Washington. According to coordinator Ed Zuckerman, the move behind the plebiscite was stimulated by what the group saw as uncontrolled spending at the five nuclear plants the supply system is currently constructing. WNP-1, WNP-2, and WNP-4 are being constructed at Richland, Wash., and WNP-3 and WNP-5 are being built in Satsop. All plants are nominal 1,250 megawatts, except unit 2 which is 1,150 MW.

Cost escalations have gone from $6.1 billion when the plants were first planned to $24 billion today. According to Zuckerman, WPPSS was not required to account for its budget in the way that private investor-owned companies have to report to public utility commissions. This led the citizen's group to formulate Initiative 394. Passage of the act essentially makes service area customers collective managers of construction; after July 1, 1982 the supply system cannot issue bonds without first obtaining voter approval. A special general election will now have to be held each time the supply system wants to issue bonds for each nuclear plant.

Under the initiative, only voters in the 23 public utility districts and cities that are supply system members would be eligible to cast ballots. The electorate essentially has the function of a review board, and will vote on each WPPSS nuclear plant as an entity.

While appeals to the initiative are likely to follow, Zuckerman said the measure had been carefully crafted to withstand constitutional challenges. "We're very confident it's solid," he

Continued on page 2

Company awaits confirmation

Sunohio reports PCBX-treated oil is okay for transformers

CHICAGO— Sunohio has analyzed the oil that has been treated by the company's PCB destruction process and reports that it is of acceptable quality to be safety returned to electrical transformers.

"Th(e) test results confirm, in all parameters, that PCBX processed oil is suitable for ongoing use in transformers," Dr. Oscal Norman, principal inventor of the PCBX process said. "We are confident that all independent laboratory analyses now being undertaken will corroborate our test results and will verify what we have demonstrated, namely, that oil treated by the PCBX process is fully reusable as an insulating fluid."

Sunohio announced the details of its PCB destruction process earlier this year, but in a feature story run in this publication, industry researchers raised questions about the quality of the transformer oil after it had been treated by the Sunohio process (see *EL&P*, July, 1981, page 1).

Results of the company's tests—which were conducted by Dr. Norman at the Sun Tech laboratory in Marcus Hook, PA—were released at the Electrical/Electronics Insulation Conference. Sun Tech is the research and development arm of The Sun Company; Sunohio is a partnership formed by subsidiaries of The Sun Company and Ohio Transformer Corporation.

In a telephone interview, Dr. Norman said the treated oil had been analyzed using accelerated oxidation stability tests.

"Although the information seems to indicate that the PCBX process actually improves the stability of the oil, I really will not claim that," Dr. Norman said. "But I would state that the stability of the oil was not harmed (by the process)."

The Sun Tech researcher also noted that he had taken six different transformer oils that had been treated by the PCBX process and subjected them to ASTM tests D-2440. The results of these tests, he said, showed that the oil had not been adversely affected by the process.

Dr. Norman also sought to correct what he saw as a misunderstanding that had developed around the PCBX process. He said some persons believe that the Sunohio process is limited to PCB concentrations of 500 parts per million or less.

"This is totally untrue," Norman said. "Our EPA approval permits processing contaminated mineral oil with no restriction whatsoever on the degree of contamination. We have commercially processed concentrations in excess of 1,200 ppm, but our mobile rigs are able to process concentrations in the tens of thousands of ppm and will do so as they are encountered in the field."

Since gaining EPA approval in three regions, Sunohio reports that it has been working with a number of organizations, including Boston Edison, Georgia Power, and TVA. The work has included destroying PCBs at these locations or in scheduling the processing of oils containing PCBs.

Reagan's energy policy

Last chance for private enterprise: DOE's Chiles

Private industry is being given a chance to make key decisions about energy investments on its own, says DOE director of policy, planning, and analysis J. Hunter Chiles. "If it muffs it here," Chiles told a Chicago energy conference, "it will blow it for 50 years."

CHICAGO — There's been a revolution in energy policy and key decisions will be made by private enterprise, not the federal government if the Reagan Administration has its way, DOE's director of policy, planning and analysis J. Hunter Chiles, told the Illinois Energy Conference here.

"If private enterprise doesn't work here," Chiles warned, "I don't see it having another chance in our lifetime. If it muffs it here, it will blow it for 50 years."

Chiles was one of several spokesmen describing the Reagan energy policy to this annual meeting of midwestern energy officials sponsored by the University of Illinois' energy policy center. Issues covered were the administration's recently published National Energy Policy Plan, the nuclear statement issued by the president, the coal severance tax problem, and the administration plan for dismantling the solar energy and conservation tax incentives put in place by the Carter Administration.

DOE's Chiles explained that there's been a key change in federal policy toward imported oil, "In the critical area of oil imports, we propose once again to adhere to free-market principles — so that we will not try to eliminate *all* imports *at any cost*. At some level, oil imports may make economic sense." The Reagan policy, he added, is to deal with the threat of oil imports by building up the strategic oil reserve.

Regarding electricity, the former Westinghouse manager said he expected demand for electricity to rise faster than the overall demand for energy and that there would be a shift away from oil toward coal and nuclear generation. He also repeated the administration's energy R&D policy which is to cut federal spending by billions of dollars and to turn demonstration and commercialization of new technology over to private enter-

Continued on page 3

Initiative 394 . . . continued from page 1

told *EL&P*.

One provision of the referendum is that before an election can be held, an independent consultant, selected by the state senate finance committee, has to conduct a cost-effectiveness study for each project and submit the results to the Secretary of State. If such a study shows a project uneconomic, the election would still be held but now voters would have an additional piece of information, Zuckerman explained.

Units 4 & 5: controversial focus

Although the Don't Bankrupt Washington organization was concerned about cost overruns in the construction of all five WPPSS nuclear plants, units 4 and 5 have been at center stage in recent months, as rising interest rates and inflation, compounded by substantial labor problems and supply system mismanagement, have threatened their existence.

Whereas the federal government, through the instrument of the Bonneville Power Administration, is underwriting the construction of Units 1, 2, and 3, no such financial safety net has been strung under units 4 and 5. BPA has contracted to purchase the power from the first three units and the revenues from the ratepayers are security for the bonds that are floated. The 88 participants in units 4 and 5 (excluding four investor-owned utilities) are all small public utility districts and, according to a supply system spokesman, all had agreed to purchase power from the plants before construction began.

What makes such an arrangement significantly less secure than the BPA purchase agreement, is that there are questions about the need for power in the area. Obviously, if demand drops, revenues of the 88 PUDs will fall, and the bonds may go to default.

The utility concedes there has been mismanagement. Prior to last year, there were no contractors responsible for overall construction management, WPPSS spokesman John Britton said. "We had an integrated system of management," he explained, "which is, in short, management by committee."

On unit 4, for example, there were at least 29 major contractors, not counting all the subcontractors. Efforts recently have been made to correct the situation, however. A new managing director, Robert Ferguson, was brought in last year. In May of this year, Bechtel Power Corporation was hired as overall construction manager for units 1, 2, and 4. Similarly, Ebasco Services was brought in to manage units 3 and 5. These moves permitted the supply system to back out of the everyday, detailed construction management role it had previously assumed, and WPPSS now oversees the work of Bechtel and Ebasco.

On October 23 four new outside members were elected to serve on a restructured executive board which will control much of the authority for running the supply system while it is building the nuclear power plants. Establishment of the 11-person executive board, which will have 7 members from the existing board of directors, was mandated in the past session of the state legislature. The legislation spelled out that all 11 members were to be selected "with the objective of establishing an executive board which has the resources to effectively carry out its responsibilities. To the extent possible, the membership and operation of the board should be patterned after boards of directors of large private corporations."

The four new outside members are C. Michael Berry, president of the Seattle-First National Bank; Edward E. Carlson, chairman, UAL, Inc.; Charles F. Luce, chairman of the board, Consolidated Edison Co.; and William E. Roberts, vice president and owner, Morgan Park, Inc.

Why financing problems?

These stairs crisscross their way up the WNP-3 cooling tower almost as steeply as the costs of the Washington Public Power Supply System's nuclear plants have climbed. WNP-3 is one of five nuclear plants the supply system has in construction and one of three that is likely to be completed. WNP-4 and WNP-5 have been "mothballed" and may eventually be cancelled.

According to a utility spokesman, when new managing director Robert Ferguson was installed in August 1980, he instituted a new "bottoms up" budget review, based on actual costs experienced rather than on cost estimates alone. He came up with a rather large increase in budget expenditures for units 4 and 5 — on the order of $1.6 billion for FY 1982. This was part of a $3 billion budget for this fiscal year for all five plants, and constituted twice as much as the supply system has ever had to raise, the spokesman explained. Because it was "extremly difficult and rather improbable" that such an amount could be raised, and because there was growing public concern that power from units 4 and 5 may not be needed, the supply system decided that it would postpone construction of the plants.

The postponement — which WPPSS prefers to call mothballing — was originally expected to be for only 6 months, but now the plants will be on hold for about 2 years, or until July 1983. But according to Don't Bankrupt Washington's Ed Zuckerman, public sentiment in the region for continuing construction of units 4 and 5 is strongly negative. He believes the plants are dead.

To the utility, mothballing means that there will be no construction, and only enough maintenance will be conducted at the sites to prevent deterioration.

It has been rough going in recent months, as the supply system has struggled to get enough money to cover mothballing costs. At first, the 88 small public utility district participants were solicited for the $150 million that was needed to bring the WPPSS mothballing fund to the required level of $400 million. However, they balked, and after considerable negotiating, an agreement was worked out whereby the participants would come up with $91 million, the four investor-owned utility participants (except Portland General Electric) would come up with $29.5 million, and regional industry (primarily large aluminum plants) would come up with the remaining $29.5 million.

While an agreement has been reached in principle, it has still not been formalized, the WPPSS spokesman said. He added that because the 88 PUD's were so widely dispered, it was simply a "matter of logistics" that final agreement had not yet been reached. A formalized accord is expected to be completed by January 1.

Mothballing costs include maintenance at units 4 and 5 and contracts for materials and overhead.

The four investor-owned utilities involved in construction of these two nuclear units are Pacific Power & Light, Portland General Electric, Puget Sound Power and Light, and Washington Water Power.

By terminating construction on units 4 and 5, the supply system calculates that it reduces its overall construction budget by nearly one-half. The original budget of $6.1 billion for construction of all 5 plants has risen to $24 billion this year. Because units 4 and 5 were significantly less advanced in construction than the other three (25 percent and 15 percent, respectively), almost half of the $24 billion was allocated for these units. Mothballing reduces the supply system's overall construction budget to about $12 billion.

To date, $2.25 billion has been sunk into units 4 and 5.

WPPSS spokesman John Britton said that contracts for all five units included the provision that interest on the plants did not have to be paid until the original dates of startup were reached. All three of these dates have passed for the first three units, and although none of these plants is yet operating, interest is being paid from the higher rates the supply system is collecting from ratepayers.

For units 4 and 5, interest payments begin in March 1983.

The supply system will not have to sell bonds for units 4 and 5 until July, 1983, assuming that it decides to resume construction. By then, the state of Washington will have delivered its analysis on the need for units 4 and 5 and the Regional Power Council will have submitted its study on the need for power.

Also by then it may be that litigation over Initiative 394 will have determined the constitutionality of that measure.

GPU agrees to buy more Ontario Hydro power

TORONTO — Ontario Hydro and General Public Utilities have signed a letter of intent for GPU to buy up to 1-million kilowatts of power for 10 years. The agreement is subject to regulatory approval in Canada and the U.S. First power could flow to GPU in early 1985 via five d-c lines.

In This Issue

Editorial 4

Acid rain is caused as much by Canadian sources as it is by U.S. power plants, according to a Canadian environmental official. **E/G** 17

Atlantic Electric is in the final stages of converting 70 percent of its oil-fired, coal-capable generating capacity back to coal. **E/G** 18

Determining safe rigging—an art or science? At Wisconsin Power & Light its an art. **T/D** 26

Computer graphics are used at Pennsylvania Power & Light to give customer useage profile. **T/D** 31

Wisconsin Electric Power has some interesting data and experience to report with a 65,000-point power-line-carrier direct load management system that controls water heaters. **E/G** 34

Reader Service 41

New Products 43

New Literature 44

Advertisers' Literature 47

Regulatory Review 51

Personnel 50

Management Methods 54

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Spent nuclear fuel storage is utility responsibility, says DOE

ST LOUIS — The U.S. Dept. of Energy has killed the Carter Administration's plan to acquire spent nuclear power plant fuel from utilities and store it in a facility to be built by the federal government, DOE's James Fiore reported to the Joint Power Generation Conference here. Fiore, a project engineer in DOE's division of transportation and fuel storage, said that utilities have the responsibility for meeting their spent fuel storage needs and for developing any new storage technology that might be needed. DOE's role, he added, will be "...encouraging and participating in the testing and demonstration of alternative storage methods by private industry." Those methods, he said, are dry storage in casks, drywell storage, silo storage, and disassembly of the bundles for compact rod storage, either wet or dry.

The new DOE projections show that spent fuel storage capacity at reactor sites will be sufficient at least until 1986, said Fiore. The Carter Administration had projected in January 1980 that away-from-reactor storage would be needed in 1981. That was based on projected nuclear capacity of 276 GW in the year 2000. The Reagan DOE, however, sees only 180 GW of nuclear capacity in place by the year 2000 and, therefore, a reduced need for external storage.

The new projection shows external storage needs beginning in 1986 and building up to 11,000 tonnes by 1198 "when a full-scale licensed disposal facility might be available," said Fiore.

That projection assumes maximum use of existing reactor spent fuel pools. Fiore said that 23 utilities plan to increase pool capacity prior to 1990 and that another 15 could be packed tighter according to DOE's analysis. Even with maximum reracking, some utilities, as shown in the table, will have a shortage of space starting in 1986. Fiore said a number of steps could be taken to handle these problems including transshipment from utilities with a lack of space to those with an excess and by not maintaining an on-site full-core reserve capacity in case of an emergency. "The department does not advocate operations without full core reserve because full core reserve is a prudent operational procedure," said Fiore. "However, it is not necessary to avoid reactor shutdowns."

The DOE official outlined the following methods for taking care of the utilities with near-term storage problems:

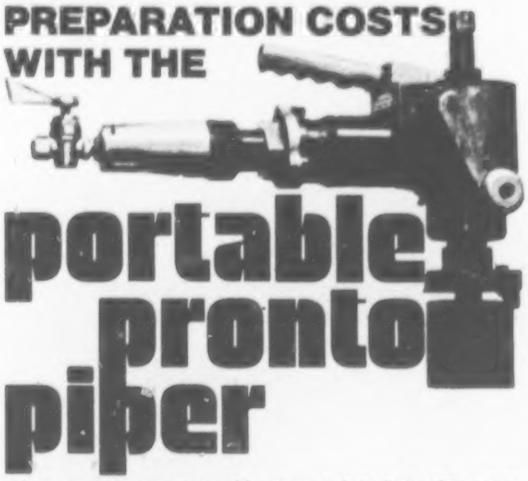
- Use of existing storage facilities such as the GE-Morris, AGNS-Barnwell, and NFS-West Valley facilities. "The absence of a federal program to acquire and use these facilities does not preclude their use by private industry," said Fiore.
- New water basin storage facilities could be built either at reactor sites or outside by utilities or by other parties, Fiore suggested. It should only take 8 years to bring such facilities on line, he said.
- Transshipment could take better advantage of existing industry capacity. "While interutility transshipments could face institutional obstacles," Fiore noted, "there are no obstacles that are safety related."
- Capacity of existing reactor pools could be doubled by disassembling the spent fuel assemblies and storing the fuel in rods.
- The fuel assemblies could be stored "dry" rather than in the water pools used to date. "Although there is significantly more experience with water storage," said the DOE engineer, "there are no known technical problems that prevent the use of dry storage."

DOE, said Fiore, will concentrate its "encouragement" and "participation" on demonstrations of the last two methods. By the end of 1982 will test the licensing and technology of BWR fuel disassemble and "rod consolidation" at the Tennessee Valley Authority. A PWR demonstration partner is being sought. DOE will also conduct an unlicensed of dry storage in casks at a DOE site in fiscal 1982, Fiore reported. A licensed demo at a utility site will be done in 1983, he added. The department is also testing drywell and silo storage at a DOE facility. The goal is to prepare a generic Safety Analysis Report for each method, said the DOE official.

REACTORS WITH NEAR-TERM STORAGE REQUIREMENTS

Reactor	State	Year When Additional Storage Capacity is Needed
Robinson - 2	South Carolina	1986
Brunswick - 1	North Carolina	1986
Dresden - 1	Illinois	1986
Palisades	Michigan	1986
St. Lucie - 1	Florida	1986
Surry - 1,2	Virginia	1986
Oyster Creek	New Jersey	1987
Maine Yankee	Maine	1987
Peach Bottom - 2	Pennsylvania	198[illegible]
Peach Bottom - 3	Pennsylvania	1987
Oconee - 1,2	South Carolina	1987
Brunswick - 2	North Carolina	1988
Turkey Point - 3	Florida	1988
Indiana Point - 3	New York	1988
Ginna	New York	1988
Vermont Yankee	Vermont	1988
Pilgrim - 1	Massachusetts	1989
La Crosse	Wisconsin	1989
Oconee - 3	South Carolina	1989
Turkey Point - 4	Florida	1989
Millstone - 1	Connecticut	1989
Monticello	Minnesota	1989
Fitzpatrick	New York	1989
San Onofre - 1	California	1989
North Anna - 1,2	Virginia	1989
San Onofre - 2	California	1990

Source: "The Dept. of Energy's Interim Spent Fuel Management Program," by James Fiore, DOE. 1981 Joint Power Generation Conference.



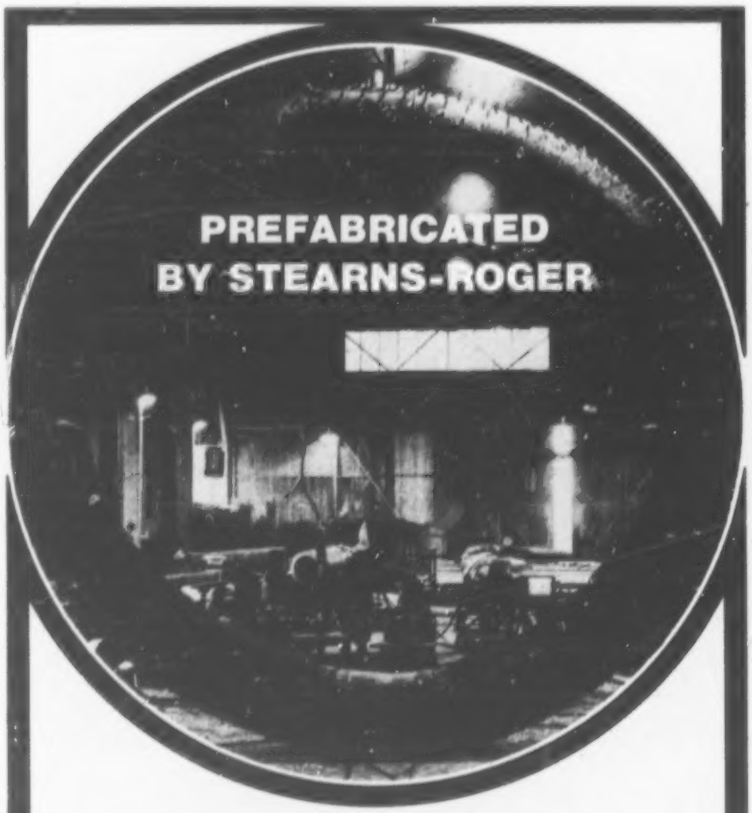
REDUCE PIPE WELD
PREPARATION COSTS
WITH THE

portable
pronto
piper

Now you can remove a weld or bevel a tube in hard to get at places—in the field or in your plant. Pronto Piper makes it easy. It will counterbore, face or mill tube ends or shorten tubes (7/8" to 4" I.D.) to any exact length. Air operated, the Pronto Piper weighs only twenty pounds and is torque-free. Requires no hold down tools. Electrically operated models available. Furnished with three sets of bits and an expanding collet. Additional collets available in 1/8" increments. Write for literature and prices.

JARNICO, INC.
P. O. Box 843 • Wooster, Ohio 44681 • (216) 262-4436

Inquire R.S. 17



Better Piping for Less Money

Pipe fabricated in the Stearns-Roger Pipe Plant results in lower installed costs. We fabricate ferrous and non-ferrous pipe ready for economical field assembly or pressure vessels and assemblies for process plants. Assembly line methods with non-destructive testing avoid the field fabrication problems that delay the job and boost costs. Call us for quote information on pipe custom fabricated to your specifications.

Since [illegible]
Service to Industry
Stearns-Roger

DESIGN
ENGINEERING
FABRICATION
CONSTRUCTION
TESTING

P.O. BOX 5888 · DENVER, COLO 80217 · PHONE (303) 758-1122

0901 14 182514C 11 ■50 1
COPY ONE
STATISTICAL REFEREN
4520 EAST-WEST HWY/-
WASHINGTON DC 20014
/C 8650-4

Volume 60, Number 1
January, 1982

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Boiler suppliers ask for investigation of "secret, illegal" foreign financing deals

Robert Smock
Managing Editor

The American Boiler Manufacturers Association (ABMA) has asked the U.S. Dept. of Commerce to investigate the possibility that foreign governments are subsidizing illegal financing deals.

The action came in the wake of meetings of the ABMA board of directors following publication of a description in the November , 1981 issue of *Electric Light & Power* of foreign financing schemes proposed for Atlantic Electric Co.

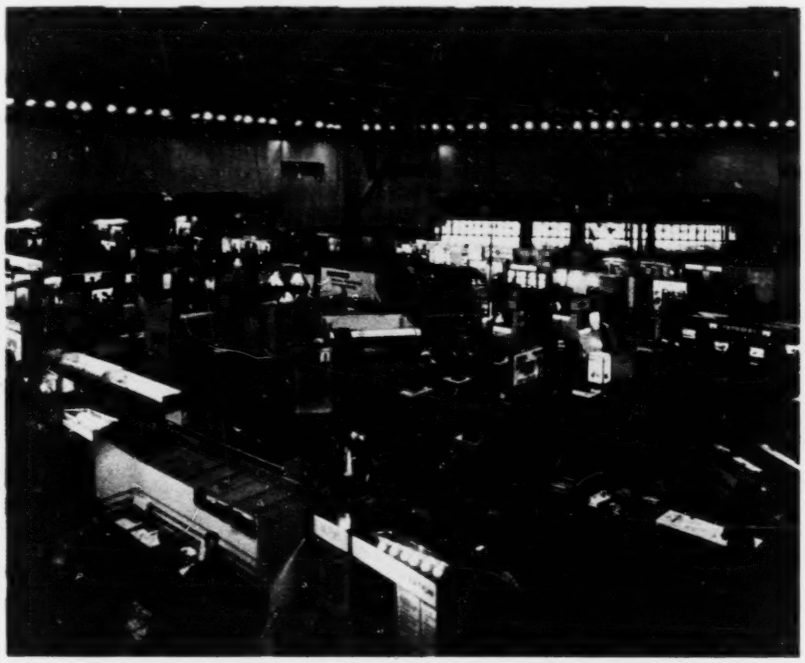
A letter from ABMA executive director, William Axtman, to Commerce Secretary Malcolm Baldridge says, "As you can appreciate, the sale of industrial and utility boilers is highly individualized, often on a sealed bid basis. Rarely are the key terms of the winning contract publicly disclosed. This fact makes the American boiler manufacturers highly vulnerable to secret illegal financing deals offered by foreign suppliers. The American boiler industry is therefore dependent on your department's capacity to ferret out the terms of illegal export subsidies, in order to lay the foundation for formal proceedings leading to the imposition of countervailing duties."

The ABMA complaint referred to two specific cases: the deal discussed by Atlantic City Electric Co. and the French firm, Cogenel, for equipment for a $550 million power plant and "...unconfirmed reports of the use of non-commercial financing terms by Gotaverken, a Swedish firm, to sell a chemical recovery boiler to Great Northern Nekoosa/KKO for a plant at New Augusta, Mississippi."

An Atlantic Electric spokesman denied that the Cogenel financing offer violates U.S. tariff law.

A bulletin sent by ABMA to its 107 member firms says that this situation has been developing for several months, adding that commercial sized units from South America are also being considered by U.S. buyers. The bulletin says there is a "presumption" that these sales include financing that is not generally available on a commercial basis, financing that is subsidized by foreign governments to spur exports from their countries. Such subsidies would be a violation of U.S. tariff law and would call for the Commerce Dept. to impose countervailing duties on the price of the imported products to cancel out the effect of the banned subsidy, explained John Kenkel of the department's office of investigations. He said the ABMA complaint had not yet filtered down to his office but that it probably would since investigations of prohibited financing are already underway. "It happens a lot," Kenkel said, especially with suppliers from European countries such as

Continued on page 8



Coal show sets exhibitor record

Exhibit space was up a whopping 45 percent at this year's Coal Utilization Exhibition in Houston. Attendees learned of new developments in synfuels, coal conversion technology, rail rates, coal exports, and new mining technology. See page 23 for a report.

NRC suspends Diablo Canyon test license

WASHINGTON, D.C. — Declaring that its staff had identified "serious weaknesses in PG&E's quality assurance program," the Nuclear Regulatory Commission has announced that it has suspended the fuel loading and low power testing license for the Diablo Canyon nuclear plant.

Although Pacific Gas & Electric, owner and builder of the two-unit nuclear station, could have appealed the NRC's order, it has decided not to do so.

Specifically, the NRC found that the utility's quality assurance program did not effectively control the review and approval of design information that passed to and from the company's major service subcontractor, John Blume and Associates.

In addition, the agency found that the company's quality assurance program did not adequately control the distribution of design information from Blume within the company.

Finally, inadequacies in quality assurance were discovered with respect to other service-related contracts.

"This new information," the NRC said in its November 19 order, "indicates that, contrary to statements made in PG&E's operating license application, certain structures, systems, and components important to

Continued on page 9

Media blitz riles consumer advocates

EEI launches ad campaign aimed at state regulators, decision makers

SAN FRANCISCO — The Edison Electric Institute launched its first media offensive for higher utility rates at the meeting of regulatory commissioners here, and was immediately denounced by state consumer advocates for subverting the regulatory hearing process.

On the second day of the annual convention of the National Association of Regulatory Utility Commissioners (November 17), two full-page advertisements appeared in both the *Wall Street Journal* and the *San Francisco Chronicle* detailing the industry's case for higher rates of return. Former Wisconsin Public Service Commission chairman Charles J. Cicchetti was shown turning away from his blackboard to inform *Journal* readers that "rates of return have been kept so low that stockholders are often subsidizing consumers," and that "unless remedial action is taken, the future may well include power rationing, routine blackouts and brownouts."

Noting that $350 billion to $500 billion will have to be spent over the next decade by electric companies to provide new plants and equipment, Cicchetti advised regulatory commissions to permit rates of return on equity of "at least 17 percent, and perhaps 19 percent or more, based on real earnings, not accounting devices."

Cicchetti also called for expedited rate proceedings, reduced regulatory lag, interim rates, and automatic rate adjustments for inflation, higher wage costs, higher capital costs, and other factors that "are clearly beyond the control of utility management."

EEI will spend about $2.5 million over the next 14 months trying to reach "those influential people who read influential publications," an EEI spokesman said.

Edison spokesman Dick Morrissey estimated that at least 9 separate ads will be run through 1982, with some of them appearing in multiple publications simultaneously. On December 7, Alvin L. Alm shared his views on "America's hidden energy crisis"

Continued on page 2

Cast Your Ballot for

ELECTRIC INDUSTRY MAN OF THE YEAR

See page 20

CECo sees 2% peak growth, governor's study may show less

CHICAGO — Commonwealth Edison Company, which has one of the most ambitious nuclear power construction programs in the nation, has reduced its estimated annual peak load growth from 3 percent to 2 percent over the next decade and there are indications that it may ultimately turn out to be even less.

In addition, the company has announced deferrment of its planned two-unit Carroll County nuclear station and has reduced estimated expenditures on its 5-year construction budget. The two Carroll County plants, each of nominal 1,120 megawatts, have been deferred from 1993 and 1994 startup to 1999 and 2000, respectively. The company's construction budget for the years 1982 through 1986 has been reduced from $5.85 billion to $5.55 billion.

In response to this estimated demand reduction, the company has also decided that it would postpone its Langham coal-fired station near Seneca, Illinois. Each of the two 550 MW units will be deferred, the first from 1991 to 1992, and the second from 1996 to 1997.

Commonwealth Edison, which experienced a 6.5 percent decline in peak demand from 1980 to 1981 (see *EL&P*, October, 1981, page 3), had been predicting, as late as October, that it would see a 17.3 percent jump in peak demand during 1982, according to a company forecast prepared for utility analysts. This figure ("An ambitious prediction," a company spokesman said) was revised in late November to reflect a peak load growth for 1982 of 10.2 percent.

Commonwealth Edison currently has 6 nuclear plants in construction, representing an additional aggragate generating capacity of 6,636 megawatts. All of these plants are well beyond the 50 percent construction completion stage and the La Salle plants are virtually ready for startup.

In its November 1, 1981 report to stockholders, Commonwealth Edison recorded a decrease of 0.6 percent in kilowatt hours sold to ultimate customers during the first 9 months of 1981. Corresponding revenues for the period were up 14.2 percent.

According to company spokesman John Hogan, the primary reasons for the reduced peak demand forecasts are conservation and the poor state of the economy.

Independent forecast by Governor

The Illinois Governor's Office of Consumer Services, noting that consumers had raised sufficiently challenging questions in CECo rate cases regarding the prudency of the company's construction program, said

Continued on page 10

EEI ad campaign . .. from page 1

IT'S TIME TO BRING ENERGY PROBLEM
AMERICA'S HIDDEN INTO THE OPEN
by Charles J. Cicchetti

Former Wisconsin regulator Dr. Charles J. Cicchetti appears in *The Wall Street Journal* as part of the Edison Electric Institute's media campaign revealing the details of "America's hidden energy problem."

by stating flatly in *The Wall Street Journal* that "the investor-owned electric utility industry is in trouble." Alm, who is director of the Energy Security Program in the Kennedy School of Government at Harvard University said the solution to the problem was, again, to allow utilities to earn higher rates of return, to be rewarded for cost-savings improvements, and to seek to meet future power needs through innovative approaches.

EEI has noted in its ads that those persons who speak for the electric utility industry are not paid for articulating their positions. In mid-December, the Institute said it was looking for additional "authoritative, knowledgeable people to recruit to do these kinds of ads."

Consumer advocates angered

Not coincidentally, the first EEI-sponsored media offensive appeared in *The Wall Street Journal* and the *San Francisco Chronicle* on the second day of the annual meeting of the National Association of Regulatory Utility Commissioners. The National Association of State Utility Consumer Advocates, which was meeting in San Francisco concurrently with the regulatory commissioners, lashed out at the industry's proposed financing program (as outlined in the advertisments) and at the program's planned implementation.

"The financial program they have put forward is deficient on its face," William A. Spratley, president of NASUCA and a state consumer advocate in Ohio charged at a press conference the day *The Wall Street Journal* ad appeared.

And according to Byron Lederer of the People's Counsel of Washington, D.C., "The inherent contradication (in the industry's) financial program is...the size of the capital expenditure (about 150 percent increase in total capitalization over the next 10 years) versus (the industry's) own forecast of about 25 percent sales growth (over the period)."

Added Lederer, "Any banker — any person with an elementary financial sense — can see that the program is a financial disaster before it is launched. That's the problem we have with it."

"Assume (electric utilities) get those rate increases," Lederer continued. "Assume that they are right, that everything that they are doing is absolutely needed for adequate, reliable service to avoid brownouts. Assume (the industry's) forecasts are right, and then assume they get their $400 to $700 million. Now what do people think that customers will do in reaction to that?"

While NASUCA estimates that raising $350 to $500 billion in new capital would require $400 to $700 billion in rate increases, Charles Cicchetti, in his *Wall Street Journal* piece, put consumer impact in terms of the increased bills that would result from utilities being granted about 50 percent increase in income. "Overall consumer bills would increase by less than 5 percent," Cicchetti said.

The consumer advocates not only denounced the details of the industry's financial plan over the next decade, but they hit what they saw as an attempt to adversely influence the regulatory process. "This is a frontal attack on state regulation," Spratley said. Declaring that what the industry was after was rapid rate increases without full regulatory proceedings, the Ohio consumer advocate said, "If they start making things more automatic, if they start being able to increase rates faster with less regulatory review, this is an attack on the regulatory process. It is not just a plan of financing. They're going to have to change laws, they're going to have to move commissions, and so forth. And this is easier in some states than in others.

"It is wholly inappropriate to try to influence public officials by purchasing newspaper ads with customers' dollars," Spratley concluded. "We will return to our states and oppose continued levies upon our customers to pay for this continuing propaganda campaign."

The issue of whether the ads were purchased with ratepayer money remains unclear. The consumer advocates claimed that customer money was used, but they offered little evidence to support this. On the other hand, the Edison Electric Institute could not say categorically that ratepayer money was not used. The institute, in fact, conceded that some of the ads probably were and would be funded by ratepayer money, but it could provide no estimate as to how much. "In certain situations it might be (ratepayer money)," EEI's Kirk Willison allowed. But, he added, determinations as to whether dues to the Institute for advertising are paid for by consumers varies from state to state. "I don't have information on how this is broken down," he said.

Commissioners react

Reactions by regulators to EEI's media blitz varied. Questioned at the meeting in San Francisco, one commissioner said that, contrasted to overall expenses of an electric utility, the cost of the program, if distributed to ratepayers of EEI member companies, would be negligible. Another commissioner commented that the EEI program was an inappropriate way to reach the public because the advertisements were not sufficiently fundamental to point out what the so-called crisis was all about. Said this regulator, "I'll now begin to scrutinize more carefully utilities contributions to EEI."

Finally, one regulator differentiated between the effect of EEI's planned capital expansion program in the short and long term. Given the current instability of the financial markets, he said, utility rates of return should be allowed to drift upward in order to keep electric companies solvent. But, according to this commissioner, the implied consequences in the longer term are potentially more severe. "Are people still going to want to buy electricity," he questioned, "at costs that are required to finance and build new power plants?"

In This Issue

Editorial 4

Coal's pre-eminence as an electric utility industry fuel was made clear at the Fourth Annual Coal Utilization Conference and Exhibition in Houston. **E/G** 23

The development of new coal conversion technology got a setback with the loss of federal funding, but work continues on several promising projects. **E/G** 27

The PCB disposal problem is large, but not as large as once feared, according to new survey results reported at an EPRI seminar. **T/D** 37

A T&D industrial engineering program has paid off for Public Service Indiana. **T/D** 40

Coal exhauster liner replacement cost has been cut by using ceramic liners. **E/G** 52

Slag rappers installed on a boiler roof can reduce the potential for injury to maintenance workers. **E/G** 53

Reader Service 63

New Products 65

New Literature 66

Advertisers' Literature 71

Regulatory Review 76

Personnel 74

Management Methods 84

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

PCB-contaminated oil problem less than formerly thought, according to survey

DALLAS — PCB contamination of insulating oil in electrical equipment is not as large a problem — quantitatively — as was previously thought, according to survey data presented at an EPRI-sponsored seminar here.

The survey response indicated there is only 100 million gallons of oil contaminated with more than 50 ppm of the polychlorinated biphenyl, or PCB chemical that was used as a fire-resistant insulator prior to 1977. Previous estimates of the amount of contaminated oil to be dealt with were five to ten times that high. Expert opinion at the EPRI seminar indicated that the PCB-laden oil could be drained, burned in utility boilers, and replaced with fresh mineral oil because the total amount is equal to only one year's supply.

The survey results, shown in Tables 1-3, were reported by W. Corey Trench, associate environmental scientist for the Edison Electric Institute. The survey produced data from 98 utilities representing almost 70 percent of all utility-owned electrical equipment. The results were extrapolated to cover the entire utility industry. The survey was part of a court-ordered program involving EEI, the Environmental Defense Fund, and the Environmental Protection Agency to gather facts to see if PCB-contaminated mineral oil transformers are to be allowed to remain in service. A final report is due on January 12, 1982 and new regulations are due on August 12.

A 'vast difference'

Looking at the survey results, EPRI's manager of transformer design projects Ed Norton said, "There's a vast difference between these numbers and previous numbers." Another EPRI official, Gil Addis, seminar organizer, said, "Two weeks ago I thought one billion gallons of contaminated transformer oil would have to be replaced. The survey shows only 100 million. We're rethinking our position."

Former published estimates by EPRI put the total amount of contaminated transformer oil at 500 to 800 million gallons. An article in the October 1981 issue of *EPRI Journal* said, "...transformer-quality naphthenic oil may not be available in sufficiently large quantities to replace all the contaminated oil at once..."

The article focussed on the need to separate the PCB material from insulating oil or to destroy the PCBs so the oil could be reused.

The new data, said EPRI's Norton, shows that the replacement problem is not so great and that reuse may not be imperative. Insulating oil production capacity is about 100 million gallons per year, he explained, meaning that replacing all the contaminated oil would require the equivalent of only one year's supply, not 5 to 10 years, as formerly thought.

That reduces the cost impact of replacement on the utility industry. Norton estimated that the cost of replacement oil would be about $1.50 a gallon. The contaminated oil has a value of $0.50 a gallon if burned in a boiler, so the net replacement cost would be about $1.00 a gallon. About half a dozen utilities have already obtained EPA approval to burn oil with less than 500 ppm in their boilers.

Data accuracy

Norton estimated that the accuracy of the data in the EEI survey is about plus-or-minus 20 percent. He said that the main reason for the difference in the estimates of the amount of contaminated oil is that the new data shows far fewer transformers in service than previously thought. Former estimates, based on NEMA numbers for large power transformers, led to overestimates of the number of medium size and distribution transformers.

The survey showed that there are only 250,000 medium-size mineral-oil transformers in place at electric utilities (rated 500 kVA to 10,000 kVA.) Earlier estimates had placed that number as high as 5 million. The survey showed 25,000 large power transformers rated 10,000 kVA and 115 kV and above and, in the small end of the range, 20 million distribution transformers rated less than 500 kVA. According to the survey 10 percent of the total amount of mineral oil in these units (one billion gallons) is

Continued on page 46

TABLE 1: AMOUNT OF ASKAREL AND OIL-FILLED EQUIPMENT OWNED BY THE ELECTRIC UTILITY INDUSTRY BY PCB CONCENTRATION

Equipment type	Number of units in the industry	Number of units containing 50 ppm or greater PCBs	Number of units containing 500 ppm or greater PCBs
Askarel transformers	39,640	39,640	39,640
Mineral oil transformers	20,227,428	2,386,077	219,918
PCB capacitors	2,800,619	2,800,619	2,800,619
Voltage regulators	145,159	20,322	2,468
Oil-filled circuit breakers	180,939	3,256	0
Oil-filled reclosers	170,158	0	0
Oil-filled switches	385,768	54,007	0
Oil-filled/Askarel electromagnets	77	—	—
TOTAL	23,949,788	5,303,921	3,062,645

In addition to the above equipment, there are 6,545 miles of oil-filled underground cable owned by the utility industry. There are limited data available on the PCBs contained in this cable that indicate PCB concentrations are below 10 ppm.

TABLE 2: VOLUME OF FLUID AND POUNDS OF PCBs CONTAINED IN UTILITY INDUSTRY EQUIPMENT

Equipment type	Total gallons of fluid	Total pounds of PCBs
Askarel transformers	8,526,404	74,597,283
Mineral oil transformers	958,365,880	262,230
PCB capacitors	7,547,669	87,552,960
Voltage regulators	17,840,968	6,707
Oil-filled circuit breakers	137,335,668	12,685
Oil-filled reclosers	3,403,670	410
Oil-filled switches/sectionalizers	1,415,769	329
TOTAL	1,134,435,026	162,432,604

DECo tests show 'Compoles' offer savings

DETROIT — Detroit Edison Co. tests of the composite wooden poles developed by Michigan Technological University (See EL&P, August 1981, page 37) indicate that the poles offer strong, long life and, if mass produced, the potential of substantial cost savings.

The poles, called "Compoles," are manufactured in a hollow, octagonal cross-section from pressure treated wood flakes bonded together with a synthetic adhesive.

According to DECo vice president of planning and research Clay Mitchell, the "Compoles" appear to be a "perfect example" of the company's continuing efforts to control the cost of delivery of its product to customers. "We have been testing 'Compoles' and 'Comarms' (fabricated crossarms) in the field with very good results. If (the poles) were mass produced, we could conserve energy and resources because we are no longer limited to using only high-strength trees," he said.

Savings increase with pole length

DECo says the varying availability and continuously escalating prices of

Continued on page 46

Lineman finds climbing a composite wood pole easy and splinter-free. Detroit Edison considers the composite poles to be strong, durable and economic if produced in quantity. A standard fir pole is at right of the octagonal, hollow composite pole.

PCB-contaminated oil . . . from page 37

contaminated with 50 ppm or more PCBs. Norton pointed that these numbers cover only electric utilities. There are a large number of transformers owned by others, such as the 200,000 mid-size transformers owned by industry, according to Norton's estimate.

Capacitor problem

The EEI survey showed that the magnitude of the problem with PCB capacitors was about the same as estimated before. As shown in the survey result tables and Norton's summary of the capacitor findings shown in Table 4, there are 2.8 million PCB capacitors in service. The portion that ruptures and spills each year is about 0.09 percent, or 2500 per year, according to the survey.

Norton's analysis in Table 4 shows that it would take about 7.5 years for capacitor manufacturers to replace the 280,000 MVAR of PCB equipment (and continue to serve current needs) at an estimated industry manufacturing capacity of 60,000 MVAR per year.

To date only a few utilities have publicly announced plans to completely replace all their PCB capacitors. EPRI is searching for a reliable method to predict incipient failures of capacitors in order to eliminate spill contamination in a more cost-effective manner, according to seminar organizer, Gil Addis.

Where's the rest of the PCB?

The earlier EPRI report on the PCB problem showed that 1.4 billion lb of PCBs were produced in the U.S. between 1929, when manufacturing started, and 1977, when it stopped. The EPRI analysis said that 3.6 percent of that total had been destroyed, 10.7 percent had been exported, 21.4 percent had been buried in landfills, and 10.7 percent escaped to the environment where it tends to persist, being relatively non-biodegradable. That leaves 53.6 percent of the original amount, or 762 million lb of PCB that still exist somewhere in the U.S.

If, as the EEI survey shows (in Table 2), there are only 162 million lb of PCBs in utility equipment, then where's the rest? Norton pointed out that there are many transformers in service that are not owned by electric utilities and that PCBs were used in a wide variety of other equipment such as ballasts for fluorescent lights.

TABLE 3: ANNUAL LEAKAGE AND SPILL RATES FOR EQUIPMENT IN THE UTILITY INDUSTRY

Equipment type	Annual % of equipment developing small leaks of ≥50ppm PCBs	Annual % of equipment developing moderate leaks of ≥50ppm PCBs	Annual % of equipment developing PCB spills
Mineral oil transformers	0.15%	<0.09%	0.007%
PCB capacitors	2.3	0.77	0.09
Voltage regulators	<0.10	<0.10	0.024
Oil-filled circuit breakers	0.27	0.19	0.008
Oil-filled reclosers	Not avail.	Not avail.	0.004
Oil-filled switches/sectionalizers	Not avail.	Not avail.	0.007

TABLE 4: CAPACITORS

Units in service 2,800,000	**Average size** 100 KVAR
MVAR in service 280,000 MVAR	**1980 Production** 21,000 MVAR

1980 Plant capacity operated at 60%

Capacity increase being accomplished by:

1. Improving productivity and operating at full capacity (100% improvement)
2. Increased demand for more KVAR per can (50% improvement)

New capacity
60,000 MVAR/year

Conclusion
To replace 2,800,000 capacitors (280,000 MVAR) and supply normal capacitor needs with above assumptions would take 7.5 years.
Estimates by the industry of 5 to 10 years for replacement seems reasonable.

READING ALUMINUM BODIES MEAN:

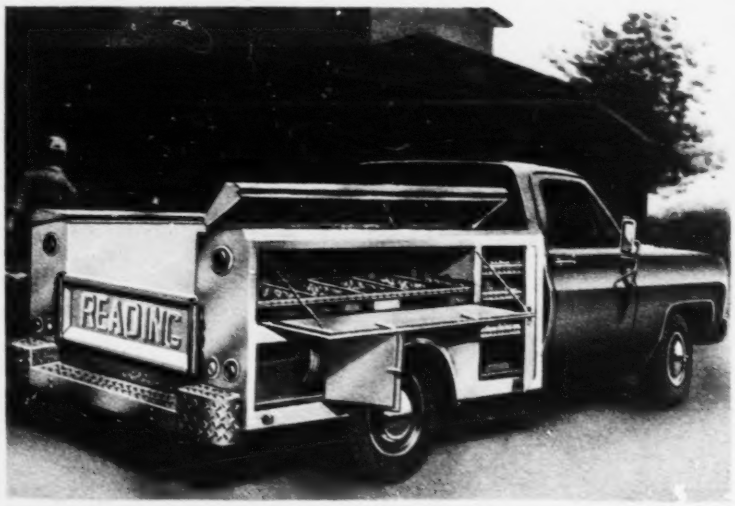
☐ LOWER FUEL COSTS
☐ HIGHER LOAD CAPACITY
☐ REDUCED TRUCK WEAR
AND MORE ...

Put a Reading aluminum service body on your full size or compact chassis and its lighter weight will save you fuel. Or load up its job-planned, weatherproof compartments with more tools and equipment without exceeding vehicle weight limits.

Airplane light with the stamina of steel, these weight-saving bodies reduce wear on tires, springs, and shocks. And aluminum's natural corrosion-resistance means virtually no body rust.

Ask your Reading dealer about Reading's quality-built aluminum service bodies. Or write for the name of your local distributor.

Reading Body Works, Inc.,
P.O. Box 14,
Reading, PA 19603.



Reading

DON'T PILE IT . . . FILE IT.

Inquire R.S. 26

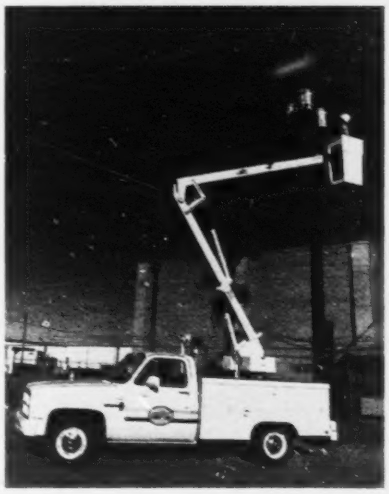
TVA dedicates nation's first electric vehicle test facility

CHATTANOOGA — The Tennessee Valley Authority has dedicated the nation's first test facility devoted exclusively to the evaluation of electric vehicles. The test tract, which is composed of a one-mile long dual banked track and a 9600 sq ft passive solar workshop and laboratory, is located here and will be used to evaluate the safety, reliability and performance of electric vehicles and their components. Present plans call for testing to determine the potential for EVs as delivery trucks, second family cars and for mass transit applications.

Leaders in the electric vehicle field participating in the dedication heralded the event as a milestone in the development of the automobile that could ultimately lead to as many as 12.5 million EVs being on the road by the year 2000, according to industry estimates.

The facility is the result of joint support from the Electric Power Research Institute and the Department of Energy. DOE is especially interested in the second-car potential for EVs.

Linemen's working lives extended



Southwestern Public Service Co., former EL&P Electric Utility of the Year (1978) and historically one of the industry's better managed utilities, says it is extending the productive working lives of its linemen by as much as 12 years through the use of pickup truck mounted aerial lift devices. Use of units as shown above, one of 34 Skyjacker bucket lifts mounted on 3/4-ton pickups, keeps linemen at their highest productivity at a time when advancing age begins to have an adverse effect.

Compoles . . .

from page 37

Douglas fir and southern pine poles prompted the search for a substitute.

The utility reports that the composite wood pole, when mass produced, will be cost competitive with a standard 40-ft pole. But savings of up to 50 percent are projectd for poles in the 80- to 100-ft range.

Other benefits

The composite wood poles and crossarms, says DECo, are less flammable and easier to handle than their solid wood counterparts, without sacrificing strength for their light weight. The poles also are smooth, clean and are easily climbed by linemen. Increased life results from extensive preservative penetration that comes from treating the wood flakes before they are compressed into the boards used to fabricate the poles. In addition, the preservative does not make the composite poles any more corrosive to pole line hardware than hardwoods.

Volume 60, Number 2
February, 1982

0902 14 1825140 11 W50 1
COPY ONE
STATISTICAL REFERENCE INDEX
4520 EAST-WEST HWY/STE 800
WASHINGTON DC 20014

-/C 8650-4 A

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

PaPUC approves GPU rate settlement

TMI-1 restart problems menace viability of agreement

Dan Utroska
Associate Editor

In an attempt to demonstrate that Pennslyvania Governor Richard Thornburgh's plan for the cleanup of Three Mile Island is working, and to financially support General Public Utilities through another potentially troublesome year, the Pennsylvania Public Utility Commission has approved a negotiated settlement that could result in aggregate base rate increases of $187.2 million.

The negotiated settlement, which was hammered out by the PUC staff, GPU's Pennsylvania subsidiaries, and the Office of the State Consumer Advocate, was approved by the full commission on January 8 by a vote of 4-0, with Commissioner Michael Johnson disqualifying himself. The settlement is a complex arrangement that provides for a series of base rate increases for GPU's Pennsylvania subsidiaries.

The first increase is to become effective almost immediately after PUC authorization of the proposal, the second increase is to be initiated upon TMI-1 restart, and the third increase is implemented when the companies' deferred energy balance (a surcharge currently being assessed GPU ratepayers in Pennsylvania) is exhausted. One important provision of the settlement is that the revenues from the $25 million and $12.5 million base rate increases that will be granted to Metropolitan Edison and Pennsylvania Electric Company, respectively, upon TMI-1 restart will be escrowed for TMI-2 decontamination.

Notwithstanding the ballyhoo surrounding publicity last fall that President Reagan was going to provide over $100 million for cleanup, and which ultimately turned out to be research and development money that had little direct impact on decontamination (see *EL&P*, December, 1981, page 20), the parties in Pennsylvania say they are optimistic that this evidence of ratepayer contributions will stimulate federal support.

Congressman Allen E. Ertel, however, and others, are noticeably less sanguine. Last October Ertel sent a letter to President Reagan asking point blank, "Does your administration intend to provide $190 million in cleanup offset costs?" (Governor Thornburgh had outlined in his cleanup plan that $190 million would be required from both the federal government and from the electric utility industry.) According to Ertel spokesman Bill Brobst, the congressman has yet to hear from the President. "We wonder about the seriousness of the administration's commitment," Brobst said.

For its part, the Edison Electric Institute has conceded that voluntary contributions to TMI-2 cleanup were not likely to flow either from the nuclear industry or from the electric utility industry as a whole. The institute is therefore seeking legislation to mandate such participation.

GPU taxes due again

Last year, as GPU neared its April tax date, it was not at all clear where the $23 million would come from for

Continued on page 6

Chinese officials host Americans

Electric utility executives participating in a People-to-People visit to the People's Republic of China were recently hosted by Ministry of Power officials. Deputy Vice Minister Su is second from left. See the Foreign Power report beginning on pages 10 & 11.

Demand, not regulations, is cause

Shearon Harris units 3 & 4, Hope Creek-2 cancelled

BARRINGTON, IL — Carolina Power & Light Company has announced that it has cancelled plans to construct units 3 and 4 of its Shearon Harris nuclear generating station and Public Service Electric and Gas Company has similarly announced that it will abandon its Hope Creek-2 generating plant.

The cancellations, which came late last year, add to the growing list of terminated nuclear plants, which recently include Boston Edison's Pilgrim-2 plant (in September), Northern Indiana Public Service Company's Bailly plant (in August), and Union Electric Company's Callaway-2 plant (in October).

What is noteworthy about the Shearon Harris and Hope Creek cancellation announcements, both of which were issued in December, 1981, is that no mention is made of regulatory problems as major contributors to the cancellations.

CP&L chairman and president Sherwood H. Smith, Jr. said the company recommended the cancellation of the Harris plants based on expectations that an expanded conservation and load management program can reduce the company's electrical generating requirement by 1,750 megawatts over the period 1982 through 1995. This would be about equal to the output of the two 900-megawatt Harris units.

"The decision was based on studies which show that with the cooperation

Continued on page 2

Banks protest Initiative 394; file court suit

RICHLAND, WASH.— Three large banks which have appreciable holdings of bonds issued by the Washington Public Power Supply System have filed suit in federal court challenging Initiative 394 that was passed by area voters late last year.

The initiative, which passed by a margin of 58 percent, was consumer response to the skyrocketing costs of the supply system's large nuclear construction program. The initiative requires that beginning July 1, 1982, any and all new bond issues by WPPSS for nuclear construction have to be submitted to voters for approval.

The banks filing suit in late December were the Seattle First National Bank, the Continental Illinois National Bank & Trust Co. of Chicago, and the Morgan Guarantee Trust of New York. The suit, which was filed in the U.S. District Court in Spokane, charges that the initiative violates the U.S. Constitution and the Washington State Constitution. According to a WPPSS spokesman, it alleges that these documents guarantee the ability of citizens to enter into contracts and obligations which the initiative impairs. Outstanding bonds were sold and purchased on the presumption that no public votes would be required to complete current nuclear projects and pay off the bondholders.

In addition, issues are raised under the Fourteenth Amendment of the U.S. Constitution regarding "equal protection of the law." The initiative creates a "peculiar voting situation" in which some Washington area citizens who have an interest in the WPPSS plants are prohibited from voting on future bond issues if they happen to live outside of the 23 public utility districts and cities that are supply system members. The WPPSS

Continued on page 2

Some fuel regs eased; other revisions pending

WASHINGTON, D.C. — Electric utilities and industrial firms will now be able to petition for exemptions to the "off-gas" provisions of 1978 Powerplant and Industrial Fuel Use Act by self-certifying their eligibility rather than supplying evidence to the Department of Energy that they are qualified.

The relaxation of the rules has been finalized for a number of provisions in the act and still others are being contemplated.

The fuel use act (FUA) was passed by Congress at a time when natural gas supplies were seen to be dwindling and it was envisioned that quantities could be extended if natural gas or oil use by new powerplants and large industrial boilers was prohibited. The act was aimed at encouraging the switch to coal or other alternative fuels with the goal of saving natural gas for "high priority" uses.

The act, however, met with stiff opposition from the electric utility industry, which maintained that it was financially impossible for gas-dependent electric companies to convert large portions of their generating capability. The industry said its generation plans already called for the replacement of natural gas, but on a more gradual schedule than the one outlined in the act (by 1990). The in-

Continued on page 3

Stop sniping at regulators, NRC's Gilinsky warns industry

Commissioner sees regulation protecting utility investments

BETHESDA, MD. — In a toughly worded message to nuclear industry representatives here, Nuclear Regulatory Commissioner Victor Gilinsky has vigorously denounced assertions by the Reagan Administration and the utility industry that nuclear regulations cause licensing delays and economic uncertainty.

"I wish I could find a way to convince you, especially those of you representing utilities, that blaming the regulators for all your ills is not a very smart tactic and will ultimately backfire on you," Gilinsky told the Washington section of the American Nuclear Society.

Gilinsky was responding to one sentence in the president's recent nuclear policy statement that the industry had highlighted in a full-page advertisement in the *Washington Post*. The statement reads, "Nuclear power has become entangled in a morass of regulations that do not (sic) enhance safety but that do (sic) cause extensive licensing delays and economic uncertainty." Referring to this statement and the nuclear industry's use of it, Gilinsky warned that "industry lobbyists can't escape responsibility for this attack on the safety regulators."

"The public may not trust us very much," Gilinsky said, "but they don't trust you at all. When the average person hears from you and the administration that the safety regulators don't know what they are doing, he doesn't conclude that the industry and the Department of Energy are right and the NRC is wrong. He concludes that nuclear energy is even more dangerous than he thought."

Declaring that Wall Street has warned that another Three Mile Island accident would signal the end of nuclear power in the United States, Gilinsky began to recite the litany of recent quality assurance problems that have cropped up during construction of nuclear plants such as Marble Hill, South Texas, and Zimmer.

With respect to operating plants, the NRC regulator said he had recently visited a plant that had been "saved from itself by NRC's firm action in imposing a strict remedial regime on the operation."

"So I ask you," Gilinsky said, "can you really be confident that all of these electric utilities are going to build their plants and manage their operation carefully without NRC supervision? Are you really ready to put your commercial future in the hands, not of the average performer, but in the hands of the *worst* performer?"

There are a lot of real problems swirling around the construction and operation of nuclear plants in America, Gilinsky said, noting that "some utilities are in over their heads." He warned that in the areas of construction and operation some utilities have lost control of their projects and have had to be reined in by the NRC.

"Who but the NRC is there to maintain a minimum standard," Gilinsky asked. "Do you really think the industry can regulate itself? I don't. Irritating as it may be, NRC performs a badly needed service, not just for the public but for the industry as well. We help keep your plants safe and thus help protect the enormous investment they represent."

And rather than giving the industry any hope that the NRC will be easing regulations, Gilinsky provided his listeners with unambiguous statements that, if anything, future enforcement will be swifter and more severe. "I think...that we are going to get tougher and you'll be making a big mistake if you fight this," Gilinsky said. "Do you really want us to ease off on the weakest of your fellow utilities? If that happens, the whole industry will end up sharing their mistakes."

Referring to the *Washington Post* advertisement, Gilinsky said that it had suggested that 33 plants could be made ready to operate in the next two years if regulators would only stop dragging their feet. "I've examined these projects," Gilinsky countered. "On the basis of our experience with nuclear construction schedules, I would guess that not more than 20 of the 33 will actually be completed by then. I'm talking about construction delays and not licensing delays."

'An Invitation'

"I wonder whether we could not put an end to this way of dealing with each other," Gilinsky concluded. "So far as I can see, it's just not in the cards for the nuclear enterprise to grow much beyond the number of current firm projects. There is no point in trying to balloon that number or to argue about where all those earlier rosy forecasts went. It's mostly the work of Adam Smith. Let's try to make sure that the reactors we are building and operating are built right and work right. NRC is an essential element. It can only do *its* job if the industry and the administration work with it, not against it."

Nuclear cancellations . . . from page 1

of our customers we can cancel these units and still meet the electrical demands of this growing region, and do this more economically than we would by completing the units," Smith said.

The Shearon Harris units were both less than 1 percent complete when the decision was made to cancel.

A lower than anticipated growth in electricity demand was also cited as a reason for cancelling the Hope Creek plant. In addition, PSE&G said it terminated that unit because of the financial burden of raising the necessary capital for construction and uncertainties as to anticipated fuel savings to offset the additional capital costs due to factors beyond the company's control. Such uncertainties were said to include future oil and coal prices, the rate of inflation, the cost of capital, electric load growth in the 1980's and 1990's, and future federal and state regulation.

"The decision (to cancel) was based largely on today's economic realities," Robert I. Smith, PSE&G chairman said. "Conservation and low electric load growth have reduced the need for new capacity in the future."

Construction of the Hope Creek unit, which had been scheduled for operation in 1989, was about 18 percent complete when terminated. Hope Creek-1 will continue as planned and in early January, 1982, the plant was nearly 40 percent complete. Planned operation is for 1986.

Recovery sought

Both CP&L and PSE&G said they would seek to recover through rates the investment they have made so far in their respective cancelled plants.

CP&L's Smith said the company will request from appropriate regulatory commissions permission to amortize the $187 million investment in Harris units 3 and 4 over a 10-year period. CP&L calculates that collecting the cancellation costs through rates will result in a lower bill to customers than if the company had continued with construction of the two plants.

"Since the investment was made for the benefit of customers, and the decision to cancel has been made to the benefit of customers, collecting the cost of this investment through rates is fair and reasonable and will be requested in our next rate filing," Smith said.

PSE&G said that it has been in discussions with the New Jersey Public Advocate's office and that they have worked out an agreement which would provide for treatment of abandonment costs. The proposed agreement has been submitted to the New Jersey Board of Public Utilities for approval.

The agreement calls for the company to recover abandonment costs estimated at $172 million, after tax reductions, beginning July 1, 1982. The amortization, if authorized, would extend over about 14 years, PSE&G said.

Because of the reduced demand forecast at CP&L—2.9 percent annually through 1990 compared with 3.3 percent of 1 year ago—the company said it would also delay unit 2 of its Harris station. The in-service date will be moved from 1988 to 1989. The first unit will stay on schedule, with a projected startup date of 1985.

CP&L also said that it would delay by 1 year the startup of its Mayo-2 coal generating unit. It is now scheduled for 1991 operation.

In This Issue

Editorial 4

Electric Power in Britain and in the People's Republic of China are reviewed in a special two-part report 10

The d-c system General Public Utilities will build to import power from Canada could ultimately serve 40 percent of Jersey Central Power & Light's load. **T/D** . . 20

A system-wide cogeneration scheme featuring coalgas fuel combined-cycle generating plants is being considered by Arkansas Power & Light. **E/G** 25

The first large-scale coal gasification facility linked to a utility power plant is currently under construction at Illinois Power and is scheduled to start operating early next year. **E/G** 37

Stone & Webster describes how it handled a tricky construction problem at the River Bend nuclear project. **E/G** 40

Reader Service 49

New Products 51

New Literature 55

Advertisers' Literature 59

Personnel 60

Regulatory Review 62

Management Methods 63

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Initiative 394 . . .

from page 1

spokesman explained that the City of Seattle, for example, although it has no interest in nuclear units 4 and 5, is qualified under the initiative to vote on future WPPSS bond issues.

WPPSS director on initiative

In a statement issued after the initiative had passed, WPPSS managing director Robert Ferguson expressed disappointment in the outcome but said he was a firm believer in the democratic process. "In this election, I believe the voters were not so much voting for the right to hold bond elections as they were voting against the cost increases of building these plants," he said.

"It is regrettable that the WNP 4/5 crisis of September and October diverted the attention and energies of most our member utilities from this important issue and that the people of Washington were not properly presented with the many sensible arguments against the initiative."

Bond issue planned

Because the initiative does not become effective until July 1, 1982, the supply system may go to the bond market before that time as the need arises. According to John Tamangi, of Lazard Freres and Co. (the supply system's financial advisor) WPPSS will continue to have very good access to the market place in the future for sales for nuclear units 1, 2, and 3.

A company spokesman said that a bond sale was being planned for the month of February. The supply system has calculated that it would run out of funding for units 1 and 2 construction by March 1 and that although the dollar figure of the proposed bond issue had not been precisely determined at press time, it was expected that the February sale would be of the order of $500 million.

AP&L sees 'window of opportunity' to double revenue via cogeneration

Arkansas Power & Light has found a way to almost double its revenue by 1985 through selling cogenerated process steam to industrial customers. "It offers an opportunity to get out of the electricity business and into the manufactured energy business," Wieble Alley, manager of energy applications for the utility company, told the Coal Technology Conference in Houston.

AP&L's electric revenue in 1980 was about $750 million. Alley estimated that the potential market value of process steam for 35 large industrial plants in AP&L's service area will be $500 million to $600 million in the 1985 to 1987 time frame.

The key to this opportunity — called the "greatest opportunity for the electric utility industry in many years" by Alley — is the approaching requirement for many industrial customers to do something about their fuel supply. The rising price and risky availability of imported oil has already led many industrial steam generators to look for an alternative. That, combined with the impending deregulation of natural gas, will create a "window of opportunity" for electric utilities to jump in and serve the market. The window will open for only a few years, Alley warned, and once it closes it will stay closed for a long time.

If industrial customers decide to buy and operate their own coal-fired steam-generating equipment, they will be committed for the next 30 years. However, Alley said he has surveyed the process heat requirements of industrial users and found a reluctance on their part to commit their capital to facilities that don't produce the product they sell. The electric utility, Alley added, is the natural developer, investor, owner, and operator of the new type of energy conversion and supply facilities needed to serve the energy market of the '80s and '90s.

Coalgas and combined cycles

The AP&L concept is based on a combination of combined cycle cogeneration and coal gasification. The cogenerating combined cycle, shown in the diagrams, is attractive because electricity output from the gas turbines can be decoupled from the process steam generated from the waste heat. A system designed to produce 4 pounds per hour of steam per kilowatt of electricity is much better suited to the market's needs than the conventional cogenerating boiler, Alley explained.

AP&L found 35 industrial customers in its service territory with process steam needs of about 6 million lbs per hour. Clusters of appropriately sized combined cycle plants could supply all this steam plus 1700 MW of electricity, Alley reported. A system owned and operated by the utility permits this electricity to be distributed through the grid, allowing much more flexibility than conventional cogeneration, he explained. He added that the primary product of the cogeneration plant would be the steam; electricity would be the by-product.

The combined cycle also provides "white elephant" insurance, according to the manager. If future market conditions change, the facility could easily convert to all-electricity production.

The problem with the combined cycle, Alley explained, is that it requires a clean fuel — a clean form of coal, in this case. AP&L explored the idea of indirect, fluid-bed air heaters but, said Alley, "The number of people who stepped forward to supply them was not encouraging."

Coalgas, he added, looks much better. There have been a number of studies of coalgas linked to combined cycles, and AP&L put together a conceptual design based on the Texaco gasification process. The output would be clean, medium Btu gas (in the range of 300 Btu per cubic foot) that could be piped as far as 200 miles, according to the utility's analysis. A central gasification installation could, therefore, serve a number of distant combined cycle/cogeneration installations. One combined cycle plant could provide steam for a cluster of adjacent or nearby industrial facilities, with the by-product electricity fed back to the AP&L system.

Another advantage of coalgas to AP&L is that it allows the system to reach the existing cogenerators. These 6 plants account for 60 percent of the total steam demand and currently produce 230 MW of electric power. (The overall system also retains the other candidates as AP&L customers because they might decide to generate their own electricity as well as their own process steam if they decided to go to coal on their own.)

The entire system, at full market penetration, would consist of an undetermined number of gasification plants producing a total of 460 billion Btu's per day. A pipeline system would carry the medium-Btu gas to the combined-cycle/cogenerating plants. These plants would produce 6 million lbs of process steam per hour for sale over the fence as their primary product. As a by-product, they would produce 1700 MW of electricity. The electrical production would be independent from the steam production because the gas turbines could be operated while the waste heat recovery boilers were shut down. The electrical production could be independent from the gasification system by keeping backup oil on site or by converting the coal to methanol, which could be stored on site.

Alley estimated that the total system would cost $5.2 billion, based on a four-year construction period ending in January, 1986. The gasification/pipeline system would account for 75 percent of the capital cost.

Two requirements for putting such a system into place are the ability to establish an unregulated subsidiary to own and operate it (the electricity production would have to remain regulated.) Alley said the utility would need partners for financing, but not

Continued on page 42

FIGURE 1
INDUSTRIAL CUSTOMER REQUIREMENTS

Process steam pph	Purchases from AP&L kW	Present cogeneration (customer owned) kW	Potential new cogeneration (above present cogeneration) AP&L owned kW	Potential new cogeneration (above present cogeneration) Customer owned kW
1,100,000	0	80,000	290,000	0
950,000	12,060	20,000	315,000	12,000
800,000	6,760	30,000	300,000	0
375,000	8,808	20,000	100,000	0
364,000	22,599	10,000	95,800	16,250
250,000	40,067	72,000	62,500	25,000
250,000	12,774	–	62,500	8,800
240,400	1,941	–	60,000	8,000
200,000	1,274	–	50,000	7,000
200,000	6,486	–	50,000	7,000
120,000	5,344	–	30,000	3,000
100,000	1,371	–	25,000	4,000
100,000	5,252	–	25,000	4,000
100,000	6,184	–	25,000	4,000
89,000	2,936	–	22,250	2,225
80,000	5,262	–	20,000	2,000
75,000	1,917	–	18,750	1,875
70,000	2,631	–	17,500	2,000
70,000	2,984	–	17,500	1,750
70,000	1,588	–	17,500	1,750
55,000	4,113	–	13,750	1,375
50,000	2,900	–	12,500	1,250
45,000	3,644	–	11,250	1,125
45,000	844	–	11,250	1,000
35,000	5,895	–	8,750	921
35,000	1,638	–	8,750	700
35,000	3,256	–	8,750	820
28,000	2,069	–	7,000	580
25,000	2,483	–	6,250	500
22,850	461	–	5,700	457
20,000	4,240	–	5,000	466
12,000	1,961	–	3,000	290
10,000	432	–	2,500	209
9,500	562	–	2,375	190
9,500	995	–	2,370	200
6,040,250	183,751	232,000	1,713,495	120,041

FIGURE 2
CONVENTIONAL COGENERATION SYSTEM

Direct combustion steam topping system supplying 100,000 pph at 160 psig D & S at 80% annual load factor

1. Process steam to power ratio (25-50 lb/kW) depending on pressure differential between steam turbine throttle and process steam	Use 38 lb/kW
2. Heat charged to process steam	1350 Btu/lb
3. Heat charged to electric power 4200 - 5000	Use 4500 Btu/kWh
4. Annual fuel savings	
A. Fuel saving for cogenerated steam (100,000 x 1350) - (100,000 x 1350)	0 Btu
B. Fuel saving for cogenerated electricity (100,000 ÷ 38) x (10,700 - 4500) x (8760 x .8)	114.4 x 10^9 Btu/yr

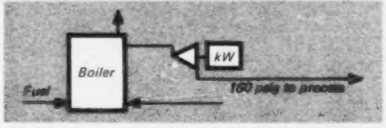


FIGURE 3
COMBINED CYCLE COGENERATION SYSTEM

Combined cycle—combustion and steam turbine supplying 100,000 pph at 160 psig D & S at 80% annual load factor

1. Process steam to power ratio—3-5 lb/kW	Use 4 lb/kW
2. Fuel input to produce 4 lb steam and 1 kW	10,400 Btu/hr
3. Fuel chargeable to power 10,400 - (4 x 1350)	5,000 Btu/kWh
4. Annual fuel saving using natural gas	
A. (100,000 ÷ 4) x (10,700 - 5,000) x (8760 x .8)	= 998.6 x 10^9 Btu/yr
5. Annual fuel savings using MBG from coal gasifier	
A. 25,000 kW x ((10,700 - (5000 ÷ .73)) x 7008 hrs	674.7 x 10^9 Btu/yr

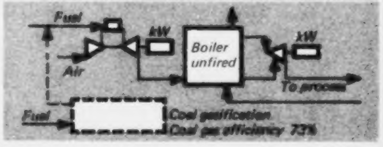


FIGURE 4
FUEL SAVING IMPROVEMENT THROUGH THE USE OF COMBINED CYCLE COGENERATION

	Electric cogenerated capacity kW per 100,000 pph of process steam	Increased cogenerated electric capacity, %	Fuel saved by using cogeneration 10^9 Btu/yr	Increased fuel saving, %
Case II				
Conventional cogeneration	2,632	Base	114.4	Base
Case III				
Combined cycle cogeneration				
A. Natural gas	25,000	850	998.6	773
B. MBG	25,000	850	674.7	490
Case IV				
Combined cycle cogeneration in repowering configuration				
A. Natural gas	26,316	900	762.4	566
B. MBG	26,316	900	301.6	163

Furnace additive reduces air-heater plugging

KINCAID, IL — A fireside chemical additive injected in the upper furnace region of two 600-MW boilers at Commonwealth Edison's Kincaid station here has solved a nagging air heater fouling problem, reports plant technical engineer John Kennedy. In the 2 years the additive has been used there's been only one shutdown to wash out plugged air heater tubes. Before, Kennedy adds, shutdowns for washing were required 5 times a year.

Tube plugging

The tube plugging was traced back to sulfur trioxide condensation which led to ash agglomerating on the tubes. The two B&W cyclone boilers burn a Southern Illinois coal with from 3 to 5 percent sulfur, 11.5 to 12 percent ash, 8.2 to 10.7 percent moisture, and a heating value of 11,000 to 12,500 Btu per lb. The stack gas had SO_3 levels of 80 to 95 ppm and the acid dewpoint was 270 to 285F. The air heater metal temperature was below the acid dewpoint, Kennedy explains, which caused the plugging problem. The solution was periodic hydrojetting of the cold-section tubes because the pressure drop got as high as 17 in. of water (gage) through the air heater.

Inorganic additive

The chemical additive program was supplied by Dearborn Utilities Services Co. The material, a blend of inorganics (not MgO), is blown in through access ports cut in the tops of the furnaces. The material works by reducing the SO_3 concentration in the combustion gas through a combination of physical absorption and neutralization, explains a DUSCO spokesman. He says the Kincaid installation was one of the first large-scale applications for this new material.

The additive feed rate varies from 50 lb/hr in the summer (when the higher gas temperature tends to be well above the acid dewpoint) to 300 to 350 lb/hr in the winter. The cold-end tube metal temperature is monitored, explains Com Ed's Kennedy, which is used as an additive feed rate indicator.

The result has been a reduction of SO_3 concentrations to the range of 5 to 8 ppm and reduced acid dewpoint temperature. Plugging has been virtually eliminated, says Kennedy. At a feed rate of about one lb per ton of coal (the units burn 260 TPH at full load each) the additive costs about 30 cents per ton of coal, a cost "definitely worth it," says Kennedy in view of the reduced downtime.

Side benefit

The additive program had a side benefit of reducing particulate emissions by improving the efficiency of the electrostatic precipitators. The SO_3 concentrations were so high in the stack gas that the fly ash resistivity fell below the optimum range for precipitator operation — resistivity was so low that fly ash was re-entraining. By reducing the SO_3 concentration, the additive program increased the fly ash resistivity, increased the precipitator efficiency, and reduced particulate emissions from 0.25 to 0.17 lb per million Btu. (New precipitators were installed at the station to meet a tightened requirement.)

Coal-to-liquid pilot plant a success: DOE

WASHINGTON — The Department of Energy says the H-coal coal liquefaction pilot plant it sponsors in Catlettsburg, Kentucky is a success. The plant completed its first long production run in December, 1981 during which it operated for 131 days, 72 percent of the time at design rating of 220 tons of coal a day. The plant converted a total of 19,200 tons of coal to a low-sulfur liquid hydrocarbon which could be further refined to produce gasoline or heating oil.

The pilot unit, which is operated by Ashland Oil Co., is expected to be restarted this spring on Wyodak coal. DOE says that it will stop paying for operating the plant in October, 1982.

Cogeneration ...

from page 37

necessarily the steam customers. Financing could come from disinterested sources who could take advantage of AP&L's tax credits, for example, under the new tax law. The utility has also proposed changes in federal law that would shield a utility-owned cogeneration subsidiary from state regulation.

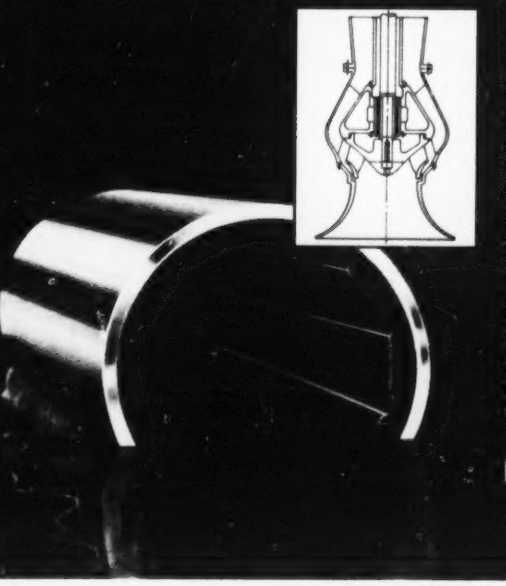
Feasibility studies are still underway and industrial prospects are still being courted, Alley told the Houston audience, adding, "this national resource for energy conservation, the industrial process heat requirement, will be frittered away through the lack of development or the use of conventional cogeneration technology unless the electric utility industry takes the leadership in developing and implementing AP&L type programs before these industries make the switch to coal-fired equipment."

Nuke construction ...

from page 41

face.

The 740-ton vessel was then walked 50 feet while being hoisted to a height of 110 feet, a first in nuclear power plant construction. Boomed out to the center of the reactor building, the RPV was lowered precisely on to 120 3-in.-diameter anchor bolts on its pedestal. The lowering of the vessel required maintenance of an 11-in. clearance between the RPV and the previously-installed shield wall which surrounds it.



This water lube bearing helps condenser pumps keep their cool.

Cutless® rubber bearings provide long, trouble-free service for condenser circulating water pumps where the revolving shaft and bearing are in contact with clean or silt-filled water.

Key to the long life, smooth operation and minimum friction offered by Cutless bearings is an exclusive "Water Wedge" design that assures a continuous film of lubricating water between shaft and bearing.

With more than 20,000 bearings in stock Moffitt can ship your bearing immediately. If you need an existing flanged bearing relined, Moffitt can handle that too. And they can custom make them to your specifications. For more information on Cutless bearings write for Bulletin 12/78.

LUCIAN MOFFITT, INC.
NATIONAL and INTERNATIONAL DISTRIBUTORS
P.O. Box 1415, AKRON, OHIO 44309

®Registered Trademark of BFGoodrich

Inquire R.S. 11

It works...
Page/Party System
when your message has to get through

The GAI-Tronics Page/Party Hazardous-Area station is engineered to get your message through where the ultimate in safety and reliability are required. This station is approved* for hazardous areas and is housed in a heavy casted enclosure to provide safe industrial voice communications in indoor or outdoor hazardous areas.

The Page/Party system delivers your message quickly and clearly with the aid of noise-cancelling transmitter, page button and party line selector switch. This system allows paging and party line conversations.

We can design indoor and outdoor systems to meet the communications needs of virtually any industrial facility—from relatively small systems to those with hundreds of stations. Call or write . . .

GAI-TRONICS CORPORATION
P.O. Box 31 • Reading, PA 19603 U.S.A.
(215) 777-1374 • TELEX 836-458

*Factory Mutual and Canadian Standards Association

Division 1 Explosion-proof Amplifier Housing
Noise-Cancelling Transmitter
Page Button
Party Line Selector Switch

Inquire R.S. 12

-1 C8650-4

3/29/82

3 14 1825157 11 W50 1
Y TWO
STATISTICAL REFERENCE INDEX
4520 EAST-WEST HWY/STE 800
WASHINGTON DC 20014

Volume 60, Number 3
March 1982

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Supreme Court refuses CEI recovery plea

WASHINGTON, D.C.—The U.S. Supreme Court has refused to consider an appeal by Cleveland Electric Illuminating Company regarding the utility's effort to recover the costs of its abandoned nuclear units.

Last July, in a ruling that reversed the Ohio Public Utilities Commission, the state supreme court ruled that CEI should not be permitted to recover from ratepayers the $56.4 million it had sunk into construction of units 2 and 3 of the Davis-Besse station and units 1 and 2 of the Erie nuclear facility(see *EL&P*, September 1981, page 1).

After proper appeals at the state level, CEI took its case to the U.S. Supreme Court. On January 25, 1982, the High Court said the company's appeal was dismissed "for want of a properly presented federal question."

According to attorney Gretchen J. Hummel of the Ohio Consumers' Counsel, provisions of the U.S. Supreme Court specify that in order for this court to have jurisdiction, federal questions must not only have been raised before the highest court in the state, but the state court must "expressly" rule on these. "The first time the company argued federal questions was in its motion for rehearing before the Ohio Supreme Court,"

Continued on page 16

FERC's 'avoided cost,' interconnection rules overturned by Appeals Court

WASHINGTON, D.C.—-The U.S. Court of Appeals in late January struck down two major rules promulgated by the Federal Energy Regulatory Commission under the Public Utility Regulatory Policies Act relating to how electric companies interact with cogenerators and small power producers.

Deciding a case brought to the District of Columbia Circuit by the American Electric Power Service Corporation, the judges vacated FERC rules requiring utilities to use full "avoided costs" in calculating how much they will pay for power supplied by cogenerators and small power producers. The court also vacated the regulatory agency's so-called interconnection rule, which was seen as giving "blanket authority" to cogenerators to interconnect with electric utilities without having to meet the requirements of certain sections of the Federal Power Act.

Cogeneration progress curtailed

The decision by the Appeals Court is likely to stall further progress in bringing forward important alternative energy production sources in the U.S. "It is important that this matter be resolved as promptly as possible, since it is likely to constitute a significant drag on the further development of cogeneration and small power production," Dr. William W. Lindsay, director of FERC's Office of Electric Power Regulation said at a recent meeting on rates in Kansas City, Missouri.

And according to Edison Electric Institute's David Owens, who also spoke at the Eighth Annual Symposium on Problems of Regulated Industries, the appeals court decision has already been stayed to give FERC an opportunity to seek a re-

Continued on page 12

Although the sun may be shining on unit 1 of the Washington Public Power Supple System's nuclear construction project, gloom has engulfed participants in units 4 and 5, as recent developments have necessitated cancellation. Even while 4 & 5 participants may be positioning themselves for legal battles over who should pay for the abandoned plants, investor demand for bonds offered in early February for units 1, 2, and 3 was so strong that the supply system upped the issue from $500 to $850 million. Above, ironworkers place the last layers of steel reinforcing bar in the latticework covering the 190-foot dome of WNP-1. Completion is targeted for April.

Perkins, Black Fox nuclear units are terminated

BARRINGTON, IL — Five more nuclear units have been scrapped. Duke Power Company has announced cancellation of its proposed 3-unit Perkins station, and Public Service Company of Oklahoma has decided that it will no longer build units 1 and 2 of that company's proposed Black Fox station.

Both utilities cited growing financial pressures attendent to constructing the plants. In a public statement, Martin E. Fate, president and chief executive officer of PSCO, said that extensive delays involved in building nuclear plants had lowered nuclear's cost advantage over coal "to the vanishing point."

Cancellation of the Perkins and Black Fox units raises precipitously the number of nuclear plants that have been terminated in recent months. Carolina Power & Light Co. cancelled two proposed Shearon Harris units earlier this year and Public Service Electric and Gas Company similarly announced abandonment of its proposed Hope Creek-2 unit(see *EL&P*, February, 1982, page 1). Late last year the Pilgrim-2, Bailly, and Callaway nuclear units were also scrapped.

In addition to regulatory uncertainties and financial challenges associated with constructing the three Perkins nuclear units, Duke Power notes that estimated peak demand has fallen significantly since the plants were first planned. Reduced demand on the system has even caused the utility to interrupt construction on unit 2 of its Cherokee nuclear station in Cherokee County, South Carolina. The 3-unit Cherokee station has been the pacing facility, a Duke spokesman said, but even here unit 3 was deferred indefinitely in 1980 and in February, 1981 the utility interrupted construction on unit 2.

When originally planned in 1974, the Perkins station was estimated to cost $1.4 billion for three units. Although precise calculations have not lately been made, comparative estimates with the Cherokee units suggest that had construction continued, the Perkins plant would have cost in excess of $10 billion.

Black Fox uneconomical

According to statements by PSCO, constructing the Black Fox nuclear units was no longer economically attractive. The Oklahoma Corporation Commission apparently thought so too because as part of a recent rate order, the agency offered guidelines

Continued on page 16

WPPSS cancels units 4 & 5; participants may challenge

RICHLAND, WASH.—-Unable to secure sufficient financing from the 88 electric cooperatives, municipalities, and public utility districts that are participants in the Washington Public Power Supply System nuclear plants 4 and 5, the WPPSS board of directors determined that it would not be possible to "mothball" the units, and so in late January voted to terminate the two projects.

Cancellation of the two nuclear plants, which had run into trouble because of system mismanagement and a statewide referendum requiring voter approval for bond issues after July 1, 1982 (see *EL&P*, December, 1981, page 1), is surely to result in an economic ripple effect, hitting particularly hard some of the smaller cooperatives and municipalities and possibly extending to the regional economy as well.

The supply system has "take or pay" contracts with the 88 participants in WPPSS nuclear projects 4 and 5, which means that even if construction of the units is never completed, as it now will not be, the participants are obligated to pay their share of the projects' costs, including the debt service on the bonds.

To date, the supply system has issued $2.25 billion in revenue bonds for construction of units 4 and 5, but according to participants' spokesman Ray Foleen, carrying this amount for 30 years means that ratepayers will eventually pay nearly $7 billion without receiving any electricity in return.

When the take-or-pay contracts between the supply system and the 88 participants were drawn up some years ago, the Bonneville Power Administration was seen running out of needed energy in the future, and contracting with WPPSS to secure power from nuclear plants 4 and 5 ap-

Continued on page 8

In-house dividend reinvestment generates capital

AKRON, OH — A stock dividend reinvestment program administered directly by Ohio Edison's own stock transfer/shareholder recordkeeping departments, rather than by a bank, is expected to produce over $30 million annually for the utility. It produces added savings by eliminating fees normally paid to a bank for reinvestment programs and by increasing shareholder participation.

"We expect to generate in excess of $30 million annually through dividend reinvestment," said Charles Glasgow, assistant secretary. "In September 1980 alone, we collected more than $5 million, and stockholders are investing about $1.5 million a month in optional cash payments through dividend reinvestment. I think we have perhaps the best plan in the country, and I also think we have the best computer-based system to operate it."

Glasgow said that Ohio Edison originally instituted the plan in the interest of stockholder relations and to remain competitive with the industry. It has now become a source of $30 million annually in capitalization needed for corporate growth.

At the time Ohio Edison took the dividend reinvestment program from a New York bank in 1976, the company had about 5,700 participants in dividend reinvestment and was producing about $2-3 million in annual revenues. After the conversion, there was a steady yearly increase of participation. Currently, there are 32,000 participants representing 16 percent of the stockholders.

Ohio Edison uses the Informatics Inc. Corporate Shareholder System, a shareholder accounting system. The utility can service shareholders who reinvest dividends and make additional cash participation purchases through maintenance of the recordkeeping function itself rather than have the agent reinvest the shares for it. Glasgow pointed out that since the in-house system is so flexible, there have been several changes made in the structure of the dividend reinvestment plan.

Participation in the plan doubled in 1978 when it was modified to offer a 5 percent discount on reinvestment dividends. In 1979 it was altered to offer a 3 percent discount for cash and a partial dividend reinvestment program was added in 1980.

"Of course we offer payroll deductions for employees." said Glasgow. "At the same time, we have changed or modified our limits to $20,000 annually, as opposed to the standard $5,000 per quarter with a minimum of $10 per payment."

"It happens to be a very convenient method for our stockholders to increase their ownership in the company by participating in the plan," he added. "They avoid any brokerage commissions or service fees, and they also enjoy the benefit of purchasing additional shares at a discount from market value."

Met Ed bank credit extended

PARSIPPANY, N.J. — The revolving credit agreement banks that have been keeping General Public Utilities on life-support since the Three Mile Island accident have decided that the holding company's present financial status is sufficiently sound to justify continued credit, thus enabling the utility to ease itself past a possible corporate default when its tax payment becomes due in April.

Last year about this time, GPU's Metropolitan Edison Company was being pulled inexorably toward the brink of insolvency as tax time approached and the company found its coffers virtually depleted. What has worked to squash a replay of this threat is the decision in January by the Pennsylvania Public Utility Commission approving a negotiated rate settlement for Met Ed and Pennsylvania Electric Company (see *EL&P*, February, 1982, page 1). A complex, multi-tiered rate increase accord, the settlement has apparently given GPU a more acceptable financial profile, allowing the consortium of 45 banks participating in the company's revolving credit agreement to continue credit to Met Ed at the present limit.

The GPU revolving credit agreement, renewed last October, required a vote of the banks by January 15, 1982, to determine whether or not they would continue support of Met Ed through 1982. Under terms of that agreement, Met Ed has a maximum borrowing limit of $43 million, of which $21 million is currently outstanding.

Met Ed's bank credit limit declines monthly, based on a liquid assets formula established by the banks. It will decline on an accelerated basis beginning in April until it reaches zero at the end of the year.

"We are pleased that the banks have viewed the recent Met Ed rate case settlement as satisfactory and have determined to provide continued support of the company," said William G. Kuhns, GPU chairman and chief executive officer.

"Today's decision by the banks," Kuhns added, "recognizes Met Ed's ability to maintain its borrowings under the limits established by the banks and the company's ability to finance its cumulative monthly bank credit reduction schedule. Most importantly, it avoids a possible default situation in April when the state gross receipts taxes must be paid."

In This Issue

Editorial 4

Calendar 17

The coal-fired power plant in the East with a zero discharge water treatment system recently started operating in Florida. **E/G** 22

PCB regulation may be tightened, pending an EPA review. **T/D** 32

A new maintenance work estimating and control system for power plant repairs and overhauls has been adopted by Commonwealth Edison. **E/G** ... 45

Reader Service 55

New Products 57

New Literature 60

Advertisers' Literature 61

Personnel 62

Management Methods 70

Regulatory Review 71

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Energy spending cut in budget

WASHINGTON, D.C. — Dismantling the Energy Department, eliminating most energy research funds and drastically reducing the government's role in energy matters are all part of President Reagan's proposed budget.

President Reagan hopes to reorganize the department by dismissing close to 4,000 of the department's 18,000 jobs and cut back those department programs that survive the reorganization. He hopes that by reducing current spending levels for civilian energy research and conservation programs, he will be able to knock off $2.2 billion from the budget.

If Congress approves, expenditures for energy would be limited to a variety of nuclear programs, filling the nation's Strategic Petroleum Reserve and providing grants for high-risk technologies.

Nearly $1 billion would be sliced from fossil, solar, geothermal and other non-nuclear research. Conservation, electric energy and storage research programs would also be wiped out.

However, no substantial cutbacks are in store for the controversial Clinch River breeder reactor. The budget includes modest funds for cleaning up Three Mile Island.

Even though the White House expects Congress to impose a fee on utilities to pay the majority of the cost to set up nuclear waste disposal sites, the budget calls for more than $230 million to live up to the "clear federal responsibility" to conduct research on proper disposal of nuclear waste.

KG&E needs more than expected to finance Wolf Creek

WICHITA, KN. — Kansas Gas & Electric Company estimates that it now will need more than $155 million in additional money over the next two years to finance its Wolf Creek nuclear generating plant.

The unanticipated increase comes from two factors, a report from the utility says. First, costs of constructing the 1,150 megawatt plant at Burlingten, Kansas, have risen from the $1.7 billion estimate made last year to just under $2 billion currently.

Also adding to the utility's cost of the plant is the fact that because of financing limits placed on Kansas Electric Power Cooperative, this public power utility has reduced its share in the Wolf Creek plant from 17 percent to 6 percent. The financing limits were imposed on KEPCo by the federal Rural Electrification Administration.

Kansas Gas & Electric says the added costs will require the utility to borrow an additional $100 million through a bank-financed loan.

Specifically, the percentage reduction by KEPCo translates into an increase in financial responsibility for the plant by KG&E of $90 to $100 million over the next 2 years, the electric company calculates. This includes $50 million KG&E must repay to KEPCo as a result of the latter making an advanced payment for expected costs.

To meet its permanent financing needs, KG&E believes it will probably have to issue about 7 million shares of common stock in 1982 and 1983.

KG&E is constructing Wolf Creek along with Kansas City Power & Light. The plant was about 70 percent complete at the beginning of 1981.

GSU headquarters conserves energy

BEAUMONT, TX — Officials of Gulf States Utilities Company say their new corporate headquarters building is a "model of energy conservation and efficiency."

A Honeywell computer activates, operates and monitors the heating, cooling, ventilation and lighting systems, with security and life safety systems integrated with it.

Jack Worthy, GSU vice president of general services, explained that "electric resistance heating will be needed only on an average of 5 days a year, and then for only a few hours in the morning to take the chill out of the air." He also said that for most of the time, heat for the building will be produced from lights, office machines and body heat.

The fluorescent lights and hot or cold air can be pre-programmed to turn on in the morning. Lights will be automatically turned off in a timed sequence after working hours, with adequate time allowed for cleaning crews to complete their work.

A variable air volume system uses sensing devices to inform the computer where cooling or heating is needed. Chilled water circulating from the central plant to mechanical rooms on each floor provides the cooling.

Pa. utilities hit new peaks

BARRINGTON, IL — A record setting deep-freeze that enveloped most of the country in January was responsible for record peak demand for General Public Utilities and Pennsylvania Power & Light.

Both utilities say that all-time peaks were reached on January 11.

GPU peaked at 11 a.m. with a demand of 6,359 MW exceeding their previous system-wide peak of 6,215 MW set January 12, 1981.

EPRI studies low-volume waste fixation

PALO ALTO, CA — The Electric Power Research Institute has published an evaluation of the state of the art of sludge fixation processes applicable to power plant wastes that might be classified "hazardous" by environmental agencies. The study, conducted by Battelle's Pacific Northwest Laboratories, found eight treatment processes that might be useful and warrant further study.

EPRI project manager Dean Golden reports that large volume solid waste streams produced in power generation are currently exempt from the strict disposal regulations required under the Resource Conservation and Recovery Act for hazardous wastes. These wastes — fly ash, bottom ash, and scrubber sludges — are currently being studied by EPA.

Smaller waste streams from power plants could be classified as hazardous, however, reports Golden. Such streams include ion exchange regeneration wastes, water treatment process sludges, metal cleaning wastes, cooling tower sludges, and miscellaneous equipment cleaning wastes.

If EPA does classify such wastes as hazardous, it may cost utilities less to transform them to non-hazardous forms prior to disposal than to comply with expensive disposal regulations. The potential for liability could also be reduced by "fixing" the wastes.

The EPRI-sponsored investigation identified eight candidate processes for treating low-volume power plant wastes, as shown in the table. The processes include cement, lime, thermoplastic, two types of organic polymer, surface encapsulation, sulfur, and glass. EPRI's Golden reports that only one process, encapsulation, is expected to be applicable for all low-volume waste types. Cost considerations, however, might favor use of less expensive methods, such as cement and pozzolanic processes. The cost range for fixation-solidification is estimated at $2 to $500 a ton.

APPLICABILITY OF SOLIDIFICATION PROCESSES ON LOW VOLUME UTILITY WASTE SLUDGES

	Solidification process							
Waste	Cement-based	Lime-based (pozzolanic)	Thermoplastic	Non-urea formaldehyde organic polymers	Urea formaldehyde organic polymers	Surface encapsulation	Glass	Sulfur-based
Boiler waterside tube cleaning sludge	+	+	+	+	–	+	+	+
Boiler fireside tube cleaning sludge	0	0	0	+	–	+	0	0
Air preheater cleaning sludge	0	0	0	+	–	+	0	0
Wastewater treatment sludge	+	+	+	+	–	+	+	+
Water treatment sludge	+	+	+	+	–	+	+	+
Cooling tower basin sludge	+	+	+	+	+	+	+	+
Cooling tower blowdown residue (evaporation)	0	0	0	+	+	+	0	0
Spent ion exchange resin	0	0	0	+	+	+	0	0

+ = Probably applicable
0 = Potential difficulties
— = Probably not applicable

Source: "Solidification of Low-Volume Power Plant Sludges," EPRI Report CS2171.

Relaxed NOx auto emissions threaten rigid plant controls

CHICAGO — If the U.S. Environmental Protection Agency follows through on its proposed plan to relax the nitrogen oxide tailpipe standard for passenger cars, it could mean that certain owners of NOx stationary sources would be required to install retrofit control equipment in order to attain the ambient air quality standard for that region, an official of the Illinois EPA said at a hearing here.

"The factors that really weigh most heavily in our recommendation (not to relax the NOx standard) are the practical regulatory implications of having large portions of Cook County designated as a nonattainment area for NO_2 after 1982," Daniel J. Goodwin, manager of the Division of Air Pollution Control told a U.S. congressional committee sitting in this midwestern city to hear testimony on revisions to the Clean Air Act.

Goodwin said that if NOx standards are made less stringent under current provisions of the Clean Air Act, it would mean that a permit moratorium for major new or modified sources of NOx emissions would have to be imposed until the ambient standard was attained. Also, retrofitting with reasonably available control technology would have to be mandated on all existing major sources of NOx.

"The most immediate impact of these actions would be blockage—perhaps permanently—of several oil-to-coal boiler conversions being considered for the area, since coal combustion produces considerably more NOx than oil combustion," Goodwin testified before the Subcommittee on Health and the Environment of the House Committee on Energy and Commerce. This subcommittee is a key subcommittee for CAA reauthorization.

Such added controls would not necessarily be confined to the Chicago area, Goodwin told *EL&P*, but could be required on power plant boilers in Denver, certain regions of California, and possibly some other areas of the country.

"Even more distressing," Goodwin said, "is the prospect of having NOx controls—NOx scrubbers, if you will—on large numbers of existing boilers and other fuel combustion sources. Control of NOx from stationary sources is a technology that is in its infancy, and it is not at all clear what technology might be judged "reasonably available" for an existing industrial boiler.

Goodwin said that whatever the decisions on this technology might turn out to be, the effect on Chicago's industrial economy was bound to be adverse. "The mere possibility that NOx control might become necessary could be sufficient to drive industrial siting choices to other locations outside Illinois," he noted. "We think this outcome can and should be avoided."

Auto vs electric industry

It is clear that environmental protection revisions aimed at benefitting the automobile industry could carry negative implications for some segments of the electric utility industry. On April 13, 1981, the U.S. Environmental Protection Agency announced its intention to take 18 special actions changing environmental regulations which, according to the agency, would save the auto industry and consumers several billion dollars over the next 5 years without significantly degrading air quality.

On August 5, 1981, USEPA Administrator Anne Gorsuch announced several "principles" on which the Reagan Administration recommendations for changes to the Clean Air Act would be based. In her press conference that day she said the USEPA would propose permanent relaxations of tailpipe nitrogen oxide and carbon monoxide standards for automobiles. This announcement greatly expanded the scope and effect of the April 13 relief package.

According to Illinois EPA's Goodwin, it is this proposed NOx revision (which would require an amendment to the CAA) that would have the greatest effect on air quality in Chicago. He said that NOx relaxation for both automobiles and trucks would cause ambient NOx concentrations to rise steadily throughout the area, beginning in 1983. This deterioration would result in pollution exceeding the primary National Ambient Air Quality Standard indefinitely into the future, even assuming the control of stationary sources.

But without such relaxations, Goodwin said Chicago air, by 1985, will have improved to the point were no nitrogen dioxide air quality violations existed—a condition that could be maintained from that point on.

'81 utility borrowing, stock sales down

NEW YORK — Total electric company financing decreased slightly in 1981.

A report prepared by EBASCO Business Consulting Company shows electric utility financing fell from $14.4 billion in 1980 to $14.2 billion in 1981. The 1981 figure includes $1.8 billion of pollution control revenue bonds, compared with $1.0 billion in 1980.

Financing by all investor-owned utilities amounted to $21.0 billion in 1981 compared to $22.1 billion last year or a 5 percent decline.

Long-term debt issued by electric companies rose 7 percent to $8.9 billion, compared to $8.3 billion in 1980. Long-term debt issued by all other utilities decreased 20 percent in 1981 from $7.0 billion to $5.6 billion.

Preferred stock financing by electric companies plunged 42 percent from $2.0 billion in 1980 to $1.2 billion. Common stock financing was $4.1 billion in 1981, a slight increase over 1980.

Offerings of preferred stock for all utilities decreased, from $2.4 billion in 1980 to $1.3 billion in 1981.

OFFERINGS OF SECURITIES BY INVESTOR OWNED PUBLIC UTILITY COMPANIES ($000)

	1981		1980	
	Total	Electric	Total	Electric
Long-term debt				
Offered publicly	13,286,895	8,256,895	13,780,400	7,445,400
Offered privately	1,173,000	672,000	1,477,400	862,900
Total long-term debt	14,459,895	8,928,895	15,257,800	8,308,300
Preferred stock				
Offered publicly	1,100,250	980,250	1,709,000	1,618,000
Offered privately	203,500	193,500	660,500	392,500
Total preferred	1,303,750	1,173,750	2,369,500	2,010,500
Common stock				
Offered publicly	5,234,034	4,[illegible]7,518	4,220,392	3,841,335
Offered through subscription	31,963	31,9[illegible]	2[illegible]4,827	221,968
Total common stock	5,265,997	4,089,481	[illegible],455,219	4,063,303
Total financing	21,029,642	14,192,126	22,082,519	14,382,103

Source: Ebasco Business Consulting Company—1982

4/21/82
C8650-4

Volume 60, Number 4
April 1982

0904 25 1830645 1 W JPK
JOSEPH MCNALLY
CONGRESSIONAL INFORMATION
SERVICE INC
4520 EAST-WEST HWY-STE 800
WASHINGTON DC 20014

Elect[illegible] & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Rossin is Man of Year

CHICAGO — Nuclear Safety Analysis Center Director A. David Rossin has been named Electric Industry Man of the Year for 1982.

Readers of Electric Light & Power voted Rossin the honor. Robert A. Lincicome, EL&P editor, said in announcing the award that Rossin was selected for his "untiring support in the development and implementation of nuclear power in the U.S. and for appearing in countless public forums to convey the electric utility industrys' message that nuclear power is economic and adequately safe."

The Award will be presented to Rossin at the All Engineers Dinner at the American Power Conference in Chicago the night of April 26, 1982. The presentation, which will be made by Lincicome, also carries with it a $1000 contribution in the winner's name to be made to the college or university of his choice. Sherwood H. Smith, Jr., chairman and chief executive officer of Carolina Light & Power, Raleigh, N.C., will be the featured dinner speaker.

Rossin is the seventh man to receive the EL&P award. Last year's recipient was Andrew L. Freeman, general manager of the Minnkota Power Cooperative.

Readers of EL&P have chosen A. David Rossin, director of the Nuclear Safety Analysis Center, as the Electric Industry Man of the Year for 1982.

EL&P Interview begins on Page 21

U.S. electric power policy planned; feds mull nationalization

KANSAS CITY, MO—-The lamentations of the electric utility industry over its inability to raise needed capital to finance new plant has gone beyond state regulators to catch the ear of Washington bureaucrats who are now thinking the time may be right for a national electricity policy.

"There has never been at the national level a comprehensive policy on electric power," Howard F Perry of the Department of Energy said at a recent meeting dealing with the problems of regulated industries. "It is absolutely striking. There has been a coal policy, there has been a nuclear policy, there has been a gas policy and an oil policy...but there has never been a policy on electric power."

Perry, who is the utility policy advisor at DOE and is in charge of the national electricity policy project, noted that the federal government has never articulated its interest in electricity nor how it would like to see that interest put forward. "It now appears that we are going to do this," he said.

Currently within the federal government are various views on what should be done in addressing a national electricity policy, Perry noted. He said that these views range from a "do-nothing" perspective, move through notions of having the federal government modify state regulations or set up operational guidelines, and come to actually having the federal government usurp state regulatory authority. Regarding the latter, Perry said, "It could be done; it's clearly constitutional. The Congress has expressed no taste for it in the past, but again, it is not entirely out of the question. And there are some advocating (this), even within the industry and within state regulation."

"The circumstances in electricity supply most likely to lead to nationalization," Perry added, "...(are) a massive shortfall of capacity. That kind of thing can bring the monsters out of the woodwork almost overnight.

"It is also striking," he said, "that we are one of the few countries in the world that continues to have a nonstate owned electric system."

Federal action: A response

Perry left little doubt that consideration of federal action with regard to electricity was seen to be not an initiative by the U.S. government, but a response to the accumulating problems encountered by the industry. "What may not be obvious," he said, "...is that the need to develop a national policy on electricity is more of a push away from business as usual than it is a pull toward any particular kind of federal policy in the future. It is a reaction to what exists, not a calling for an alternative."

> ***"There are a lot of folks who feel that the problem is the electric utility industry and 'fixing' it may be precisely the wrong thing to do. What we want is electricity, not the electric utility industry the way we know it . . ."***

And if the federal government now believes it must weigh action to modify "business as usual," Perry sees a corresponding attitude on the part of the electric utility industry and regulators. Mentioning the White House meeting held in early February in which 15 representatives from utility companies, nuclear vendors, Wall Street and state commissions gathered to discuss with Vice President Bush the status of nuclear power, Perry reported, "The meeting very quickly shifted away from a discussion of nuclear problems toward a discussion of the underlying electric utility problems. And I can report that there is an absolute consensus, that business as usual in the utility industry and in regulation is not going to cut it—that it is going to lead to very substantial problems within 10 years and that somebody at the federal level ought to begin to pay attention to those problems right now before it is too late."

At this White House meeting, Perry said, there were some who advocated certain versions of nationalism but, he added, "Nobody—not a one—recommended business as usual and

Continued on page 9

NRC commissioners clash over new safety goals

WASHINGTON, D.C.—-The Nuclear Regulatory Commission has issued for comment its proposed policy statement on safety goals for nuclear power plants, and even before the first response has been received disagreements are emerging from within the agency over the relevance of it all.

"Starting with a grand overall safety goal has the appeal of logical neatness, but it is not the way to go about dealing with our needs. . .," Commissioner Victor Gilinsky protested. He noted that what was important in the present reactor licensing climate was to devise specific guidance for dealing with "some very difficult practical questions."

"The most pressing one," he said, "is how to handle 'backfitting,'—that is, to what extent shall new requirements be applied to plants that have already received authorization for construction or operation? As a practical matter, essentially all the decisions the commission will face over the next decade will be of this type."

Proposed policy issued

In its preliminary policy statement the NRC outlined some qualitative safety goals and some provisional numerical guidelines, both of which, when modified by appropriate comment, are supposed to reflect the agency's determination on the acceptable level of risk to public health and safety and on the cost-benefit tradeoffs in regulatory decisionmaking.

In essence, the commission has proposed that *individual* members of the public should not be burdened with any significant additional risk to their health and safety because of nuclear power plants. In addition, it is

Continued on page 12

Hope Creek-2 recovery told; PSE&G to stress 'alternatives'

NEWARK, N.J.—-Details on how Public Service Electric & Gas will recover its investment in its now-abandoned Hope Creek-2 nuclear plant have been released by the New Jersey Board of Public Utilities here.

While nuclear plant abandonments have become increasingly common in recent months, cancellation of the Hope Creek-2 plant is noteworthy for two reasons. First, it is a plant that is further along in construction than others that have been cancelled recently—over 18 percent. Second, abandonment was initiated by the New Jersey Public Advocate's office and termination was based on a proposed agreement among the utility, the advocate, and the Board of Public Utilities to approve recovery (see *EL&P*, March, 1982, page 3).

Abandonment loss estimated

The projected cancellation loss specified by PSE&G for the Hope Creek-2 plant is $291 million, which includes $190 million for Public Service's 95 percent share of construction expenditures through the end of 1981. (Atlantic City Electric owns the other 5 percent.) More than $47 million is included in the calculation for the cancellation of nuclear fuel contracts, and $33 million for carrying charges on the investment, less $4.8 million in salvage credits. The board has directed the company to explore all opportunities for increasing the salvage credits and said it would review the

Continued on page 15

Regulatory ratchet clicks, nukes are abandoned, but Nuclear Regulatory Commission envisions brighter future

Dan Utroska
Associate Editor

Regulatory uncertainty, together with difficulties in raising capital and declining load growth, is nearly always cited when an electric utility decides to cancel a proposed nuclear unit. But when a company abandons a nuclear plant, it is seldom clear precisely what impact the ever-growing federal regulations actually played in the host of factors leading to the termination decision.

There is one group of plants, however, which, because of the post-Three Mile Island ratcheting bind, can legitimately point to special regulations aimed at them. This group consists of those plants that had applied for a construction permit before the TMI accident but had not been granted one by the NRC. The cries of utility managers of these plants are particularly plaintive as they point to these special requirements while announcing abandonment of their nuclear plans.

Referring to these regulations, which originally ensnared 11 plants after the TMI accident, Boston Edison Company president and chief executive officer Francis M. Staszesky asserted at the cancellation of the Pilgrim-2 nuclear unit, "Of particular significance to the Pilgrim-2 project was the requirement that construction permit applicants commit to review certain major facility modifications 2 years after a construction permit is issued. These potential modifications represented significant exposure to redesign, construction retrofits, project delay and increased cost. Therefore, even if we assumed that a construction permit was obtained by April, 1982, we would be proceeding with a project with an uncertain scope, cost, and schedule."

Out of the 11 plants that the Nuclear Regulatory Commission initially identified after the TMI accident as being the objects of tailored regulatory obligations, only five remain publicly committed to construction. From a practical standpoint, there may only be one left and that project is being reevaluated. This group consists of those plants that had applied for a construction permit before the TMI accident but had not yet received it.

Originally, the group consisted of Boston Edison's Pilgrim-2 plant; Portland General Electric Company's Pebble Springs, units 1 and 2; Puget Sound Power & Light's Sakgit units 1 and 2; Duke Power Company's 3-unit Perkins station; Public Service Company of Oklahoma's two-unit Black Fox plants, and the single unit Allens Creek plant now being contemp[illegible] by Houston Lighting and Power Company.

Electric Light & Power has recently reported the cancellations of the Pilgrim, Perkins, and Black Fox units. While the Pebble Springs and Skagit plants remain officially committed to construction, both projects are facing major obstacles to continued progress. "The economic and financial factors would have to improve significantly before we would commence construction," a spokesman for Puget Sound Power & Light said, referring to the Skagit plants. "We would need some assurance that the licensing requirements will remain constant." In addition, a study is currently underway in the region to determine long-term electricity demand. Results of the survey are expected to be issued in about a year. "Construction will not start unless these 3 elements (financing, licensing, and demand) are met," the Puget spokesman explained.

Portland General Electric Company currently believes that its two proposed Pebble Springs plants "are too costly to terminate at this point," and development of the project is, accordingly, proceeding slowly, a utility representative said. Although the post-TMI regulations implemented by the NRC are seen to potentially impact construction of this plant, Portland General Electric finds itself with a lot of nuclear equipment on hand while facing a number of more imminent obstacles to construction. requires the establishment of a feder- These include the state statute which ally licensed nuclear waste repository before any additional nuclear plants can be built in the state. A popular vote in the state permitting nuclear construction is also required, a company spokesman said.

While Portland General Electric may be wondering what to do with over $100 million worth of equipment if the plants are not built (including a nuclear steam supply system, turbine, and other hardware), Houston Lighting and Power Company is trying to locate potential buyers abroad for the nuclear steam supply system it has purchased for its proposed Allens Creek nuclear unit, one of the initial 11 in the post-TMI construction application catagory. It is this plant that the NRC sees as still being a live project.

But in late January the utility announced that it was reevaluating its plan to construct the proposed 1,200 megawatt plant and the company said that it would consider building a coal-fired plant at the site instead. While HL&P spokesman Graham Painter stopped short of saying that Allens Creek was dead, he noted, "We recognize that we do have a lot of problems with licensing—not problems, unknowns." Houston Lighting & Power filed its construction permit application with the NRC in August 1973 when a proposed two-unit plant was estimated to cost about $1.2 billion. Today, with one of those units already scrapped, the other unit alone is expected to cost $2.1 billion. If the utility can find a buyer for the hardware it has for sale, this could expedite abandonment of Allens Creek.

HL&P has two other nuclear units in construction; both units of the South Texas Project are well along in the building process.

New NRC construction regulations

What has hit this category of proposed plants is the series of regulations that were promulgated by the Nuclear Regulatory Commission last year and which became effective February 16, 1982. In essence, the new requirements fall into three classifications. First, a "probabilistic risk assessment" has to be conducted at each plant no later than 2 years after it receives its construction permit. The agency's plan here is to use this relatively new statistical mechanism in order to identify weaknesses in plant designs. While the PRA is viewed as providing more sophisticated methods for designing safety systems, it also threatens excessive backfitting and this is what scared Boston Edison and presumably a number of other utilities that have recently cancelled nuclear plants.

Second, those plants that got caught in the NRC's new licensing net were required to have containment structures that were stronger than those of similar plants already in construction.

Finally, as a result of the Three Mile Island accident, these 11 plants that had applied for a construction permit were required to have more sophisticaed hydrogen control features.

While these requirements, in varying degrees, contributed to the cancellations of numerous nuclear projects recently, the rules have apparently not dissuaded Westinghouse from envisioning completion of its offshore power plant manufacturing facility sometime in the future and thereby keeping its application current with the NRC for a manufacturing license. A manufacturing license is basically a construction permit without a site.

NRC attempts to end ratcheting

Although it is an independent agency, the NRC currently is coordinating its efforts in the regulatory area to harmonize with President Reagan's vision of reducing statutory requirements on industry enterprises. Late last year the agency set up a new department to review generic reactor requirements and to act as kind of a watchdog for regulatory changes proposed by the NRC staff.

"There has got to be some point at which these (new reactor) requirements stop," Dr. Thomas E. Murley, director of the NRC's Regional Operations and Generic Requirements staff said. Murley, who as former director of the Division of Safety Technology largely oversaw the agency's construction permit rule changes that smashed into utility plans to build 11 nuclear plants, is now working to review and restrict nuclear plant modifications proposed by the staff unless they can be shown to be needed.

"We have never really been able to control backfitting and (regulatory) ratcheting," Murley conceded, but notwithstanding this he is hopeful the agency's "final design approval" rules will be able to accomplish this. Such an approach to licensing, which would standardize certain nuclear plant designs so they could be referenced by utilities desiring to build nuclear plants, leads Murley to believe that slowing the rate of new requirements is possible.

"There are no guarantees," he allowed. "There is just the feeling that the level of review and understanding is much higher now than even 5 years ago. This commission appears to be determined to go ahead with a policy on standardization of nuclear plants."

The standardization concept would permit reactor manufacturers to submit to the NRC plant designs that could be used as a "standard" for any utility wanting to construct a plant of that type. If the plant met all applicable requirements, it would be given a final design approval, which, according to Murley, would be held unchanged for up to 10 years, given the absence of some TMI-type event. NRC review of the construction of these plants would be very limited, Murley said, and would be conducted principally to determine that the plant had been built according to specifications. One of the current day phenomena this idea is aimed at eliminating is plant design that is only a few months ahead of construction. This, Murley said, is the case with the South Texas project nuclear plants being built by Houston Lighting and Power.

Standardizing complicated plants

To some industry observers, efforts to standardize complex and crowded nuclear plants is tantamount to institutionalizing a nightmare. The Electric Power Research Institute has recently reported that U.S. nuclear utilities are unhappy with the complexity of these light water reactor plants and the California-based research organization had set out to determine how the plants could be simplified (see *EL&P*, June, 1981, page 1).

But earlier this year, EPRI decided that it would "redirect" this research effort, putting its present effort into

Continued on the next page

In This Issue

Editorial 4

A. David Rossin, director of the Nuclear Safety Analysis Center has been voted by EL&P readers as Electric Industry Man of the Year. A profile by Assistant Editor Don Minner 21

Corporate foresight at Baltimore Gas & Electric in constructing that company's two-unit Brandon Shores Power plant is resulting in one of the neatest coal conversions ever. **E/G** 33

PCB destruction techniques have eased toxic disposal for many utilities. **T/D** 47

The Reagan Administration's FY 1983 budget has virtually eliminated fossil energy research. **E/G** 64

Calendar 25

Reader Service 75

New Products 77

New Literature 83

Advertisers' Literature 86

Regulatory Review 99

Personnel 88

Management Methods 100

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Editorial

Extended nuclear fuel burnup program cut would cost U.S. dearly

Federal budget and tax cuts are long overdue. Unfortunately, in the rush to hold deficits down, increase defense appropriations and still fund popular social programs, a number of small, little-publicized but still highly beneficial programs will be eliminated or, at best, extensively whittled down.

One in this latter category is the Department of Energy's extended nuclear fuel burnup program, a 6-year old effort designed to develop a reactor fuel that will release two-thirds more energy than current fuels. Slated to be completed by 1988, the extended burnup program, according to DOE and confirmed by the General Accounting Office, could produce savings for users of electricity of $12 billion by the end of the century, resulting in a benefit-to-cost ratio of 385:1.

Benefits include the prospect of reducing total nuclear generation costs by 2.5 percent, slashing spent fuel production by 40 percent and reducing the waste storage requirement. Fuel cycle costs could be cut 10 percent and potential worker exposure to radiation reduced, supporters of the program insist. With higher plutonium content per spent fuel rod, the extended burnup fuel could reduce plutonium recovery costs by some 17 percent, cut breeder startup fuel inventories and increase breeder conversion rates up to 5 percent, according to Combustion Engineering's Dr. N.L. Shapiro.

The budget request for the extended fuel burnup program for next year was $15 million, a tiny amount by government standards. But the Office of Management and Budget would cut this by $3 million.

OMB also would reduce the development program to a single fuel design where eight or more have been under development in the past. Since there are two basic types of reactors — pressurized water reactors and boiling water reactors, each of which needs its own type of fuel — and as many as five different vendors' fuel designs, a single fuel development program would be almost useless. Moreover, reducing the extended fuel burnup program to development of a single fuel design would quickly end U.S. world-leadership in that area, probably the last area of world leadership left to U.S. nuclear system suppliers.

The prospects of the program being carried on by fuel vendors are virtually nil. Fuel vendors already are suffering from demand declines. And with almost three-fourths of fuel requirements for the next 25 years already under-contract, the incentive to develop a fuel that lasts longer is minimal. Most nuclear utilities, forced to pass through to customers any fuel savings, yet finance such a fuel-use improvement from money that costs more than the utility can earn on it, won't pick up the tab. And EPRI, despite high interest, is limited by post-TMI safety and reliability requirements and is currently budgeted for $2.5 million, probably a limit for the next few years.

In other words, if the U.S. is to have an extended nuclear fuel burnup program, it appears the funds must come from government. But in the highly politicized process of budgeting in Washington, the bigger the program budget the greater its importance. Recognizing this, it is easy to see why OMB believes it can safely slash $12 million from the DOE budget. But if Congressional committees allow such a budget curtailment, we shall lose far more than we'll save, even in the short-term.

Robert A. Lincicome
Editor-in-Chief

Air basin plan revised and relaxed

NEW CASTLE, PA — Appoval of a revision in the Upper Beaver Valley Air Basin Plan has eliminated the need for millions of dollars of scrubbers at Pennsylvania Power Company's New Castle Power Plant.

The plan approved by the Environmental Protection Agency, allows a slightly relaxed sulfer dioxide emission limit of "no more than 2.8lbs. SO_2 per million BTUs on a 30-day running average basis."

Penn Power had estimated that scrubbers would cost $85 million and approximately $14 million to operate annually.

Revised limits

Under the appproved revision, the same SO_2 emission limit that applies to the Allentown, Johnstown, Reading, and Erie air basins now also applies to the upper basin. Previously, the limit that regulated the upper basin area was the same as that used for downtown Pittsburgh.

DOE: Utility industry's financial curbs don't mean energy shortages thru '95

WASHINGTON, D.C. — Even with certain financial constraints, electric utilities will be able to satisfy customer requirements up to 1995 with acceptable levels of reliability if additional gas turbines are built to meet peak demand, a government study has concluded.

The research, conducted by the Energy Department's Energy Information Administration, also found that the financial contraints could actually provide some short term financial benefits.

"Lower capital expenditures would reduce utilities' requirements to secure investment funds at high interest rates and would reduce the pressure for higher electricity prices in the immediate future," the report said. It was noted, however, that electric companies would have to continue to make minimum capital expenditures to complete new construction already underway, perform maintenance, and conduct general operations. "Thus," the report concluded, "deterioration of common stock prices and book values and of the general financial condition of the industry could continue regardless of reduced absolute levels of capital expenditures."

The report is called "Impacts of Financial Constraints on the Electric Utility Industry," and was prepared by the EIA's Office of Coal, Nuclear, Electric, and Alternate Fuels.

Two cases examined

The report investigated two hypothetical cases, one in which capital spending was relatively unrestrained and another where financial constraints were imposed. The Edison Electric Institute has calculated that $338 billion will be needed during the rest of the 1980s for new plant construction and as can be seen from the table, the Energy Information Administration, estimating a comparable figure for a slightly longer time period — 1979 through 1990 — has reported $389 billion (in 1980 dollars) for its unconstrained—or base—case.

The estimate of financial constraint is seen by the reduction, of nearly 29 percent, from the estimated funding available in the base case in 1990. Overall conclusions are based on projections of 3.2 percent growth in demand over the period.

In addition to the longer-range negative effects on utilities under financial contraints, the EIA determined that continued financial pressure on the industry would not allow most utilities to make optimal economic decisions to expand generating capacity or to replace existing oil-fired and gas-fired power plants. This restriction, in turn, is said to be capable of producing a number of serious adverse effects on the industry in the long run.

First, the EIA found that the failure to build "more efficient" coal and nuclear plants would mean foregoing an opportunity to eliminate about 82 percent of current oil and gas use by utilities. The results of this were seen to be higher fuel costs and attendant distortions for fuel consumption in other sectors of the economy. In addition, the report said, this use of oil could cause the continuation of U.S. dependence on imports.

Unfortunately, the statistical rationale underlying DOE's findings that the failure to build "more efficient" coal and nuclear plants would have serious negative impacts later on are not included in the present report. Queried about the absence of oil supply, demand and price data in the analysis, one DOE analyst involved with preparation of the report said, "Not including it was an oversight. It had been in the first draft."

The oil supply, demand, and price data, it was explained, were taken from an earlier report sent to Congress by DOE. In essence, oil prices

Continued on page 98

COMPARISON OF CUMULATIVE UTILITY CAPITAL EXPENDITURES—BASE CASE VERSUS FINANCIAL CONSTRAINTS CASE (BILLIONS OF 1980 DOLLARS)

	1985		1990	
Category	Base Case	Financial Constraints Case	Base Case	Financial Constraints Case
Coal	48.4	23.4	131.8	58.4
Nuclear	63.1	55.1	86.0	61.9
Transmission and distribution	65.0	65.0	116.3	116.0
Other	23.5	20.0	55.1	41.1
Total	200.0	163.5	389.2	277.4

Note: Data represent estimates of cumulative capital expenditures from 1979 through each of the milestone years. Expenditures for power plants and facilities under construction on or before 1990 and scheduled for operation after 1990 are included in the tables.

Electric Light & Power

ELP® Staff

Group Publisher
Robert J. (Duke) Kiesel

Assistant Publisher
Henry A. Petersen

Editor-in-Chief
Robert A. Lincicome

Editorial Staff
Robert W. Smock, Managing Editor
Dan Utroska, Associate Editor
Donald F. Minner, Jr., Assistant Editor
Dawn Vernola, Presentations Editor
Elisa Girard, Art Director

Contributing Editors
William Kenworthy, Legal/Regulatory
Ted Pollock, Management

Production
Salvatore Pisano, Director
Margo Moore, Manager

Circulation
Joseph J. Zaccaria, Director

Marketing Services
John P. Kaiser, Director

Research
Edward Janoskey, Manager

Editorial Advisory Board

Howard C. Barnes
Chas. T. Main, Inc.

H. L. Culbreath
Tampa Electric Co.

J. Carl Ferguson
Kaiser Aluminum & Chemical Sales, Inc.

Clayton K. Larson
Northern States Power Co.

Peter J. McTague
Green Mountain Power Co.

Edward A. Myers, Jr.
Southern California Edison Co.

Ragan T. Phillips
Fluor Power Services

Roger J. Sherman
Ebasco Services, Inc.

John T. Stiefel
Stiefel Associates, Inc.

Technical Publishing
DB a company of The Dun & Bradstreet Corporation
Barrington, IL 60010 • (312) 381-1840

ELECTRIC LIGHT & POWER (USPS 858-860) is published monthly. Copyright 1982, by Technical Publishing, a company of the Dun & Bradstreet Corporation—all rights reserved. James B. Tafel, Chairman; John K. Abely, President; Robert L. Dickson, Executive Vice President; John R. Emery, Senior Vice President; Robert J. (Duke) Kiesel, Publisher, Editorial and Executives offices: 1301 S. Grove Ave., Barrington, IL 60010. Phone (312) 381-1840. Distributed by controlled circulation to executives and engineers in U.S. electric utilities and consulting engineering firms. To all others there is a subscription charge of $34 per year (U.S.), $40 (Canada) and £36 foreign, (£62 foreign air mail). Sole agent for all subscriptions outside the U.S.A. and Canada is J.B. Tratsart Ltd., 154a Greenford Road, Harrow, Middlesex HA 13QT, England. Single copy prices $4.00 (U.S.), $5.00 (Canada) and £5 (Foreign); Second-class postage paid at Barrington, IL 60010 and at additional mailing office. Postmaster: Send 3579 to ELECTRIC LIGHT & POWER, 1301 S. Grove Ave., Barrington IL 60010

ABP
BPA

Advertiser and advertising agency assume liability for all contents (including text representation and illustrations) of advertisements printed, and also assume responsibility for any claims arising therefrom made against the publisher. It is the advertiser's or agency's responsibility to obtain appropriate releases on any items or individuals pictured in the advertisement.

ADVERTISERS' INDEX

A

Acurex 56
Allied Chemical
  An Allied Company 12
Amax Coal Company 32
American Fly Ash Company 69
American Nuclear Society 62
American Pulverizer Company 73
American Science & Engineering, Inc. 82
Aramco Services Company 17
Arizona Public Service Co. 91
ATL Inc. 86

B

Babcock & Wilcox,
  Utility Sales & Marketing 20, 36-37
Baldwin Associates 93
Black & Veatch 13
Boiler Tube Company of America 29
E.J. Brooks Co., Inc. 15
Burns and Roe, Inc. 95

C

C-E BASIC,
  Basic Chemicals 59
C-E Power Systems,
  Combustion Engineering, Inc. 40-41
Carlon,
  An Indian Head Company 5
Caterpillar Tractor Co. 14
Chemical Waste Management 87
Clark Company Inc., David 78
Cleveland Electric Illuminating 92
Conversion Systems 70-71

D

Dillon & Co., Inc., W.C. 55
Ditch Witch Equipment/
  Charles Machine Works 46
Dow Chemical U.S.A. 88
DUSCO,
  Dearborn Utility Services Co. 74

F

First Interstate Bank
  of California 18
Fluor Power Services, Inc. 8
Foster Wheeler Energy Corp. 60-61
Fuller Company 39

G

Gai-Tronics Corporation 62
General Electric-Nuclear 30-31
GPU Nuclear,
  General Public Utilities Corp. 97
GTE Products Corporation,
  Security Systems Dept. 101

H

HARCO 56
Hitran
  Division of AGEX 85
Homac Mfg. Company 58

I

Inner - Tite Corp. 86

J

Jarnico, Inc. 66

K

Kerr-McGee Coal Corp. 23
Kershaw 49
Kimberly-Clark Corporation 102

L

Landis & Gyr 10-11

M

Moffitt Inc., Lucian Q. 66
Multi-Amp Corporation 99

N

Norco Services 95

O

Oreck Corporation 78, 83

P

Pacific Gas & Electric 94
Parker Sweeper Company 16
Pennsylvania Power & Light 96
Perfex Group,
  McQuay-Perfex Inc.,
  Energy Systems Division 68
Pickands Mather & Co. 34
Portec Railcar Division 65

R

Reading & Bates Coal Co. 72
Renold Inc. 66
Rockwell International,
  Energy Systems Group 67
Rocky Mountain Energy
  A Subsidiary of Union Pacific
  Corporation 19
RTE/ASEA Corporation 6-7

S

S&C Electric Company 44-45
Sargent & Lundy Engineers 24
Scientific Columbus 85
Sherman & Reilly, Inc. 58
Stearns-Roger 42
STK Condenser Service 79

T

Tension Stringing Equipment 57
Thiermann Utility Equip.,
  Div. of Racine Federated 54
Torrey Pines Technology
  A Division of
  General Atomic Company 28
TransData, Inc. 53

U

Unibus, Inc. 77
U.S. Nuclear Regulatory
  Commission 95

V

Vacco Industries 63

W

Werner Co. Inc., R.D. 54
Western Precipitation Div.
  Joy Manufacturing Company 35
Westinghouse Electric Corp.
  Meter and Low Voltage
  Instrument Transformer Div. 50-51

Nuclear too costly...

from page 24

per kilowatt and $4,400 per kilowatt. This is to be contrasted to the capital required to build coal units, which came in between $2,168 per kilowatt and $2,506 per kilowatt.

While a spokesman for Public Service Company of Oklahoma generally verified the calculations on levelized busbar costs reported by the OCC, the company was more vigorous in stressing the political and regulatory atmosphere in which it saw itself operating. "These are what really killed the project," Vaughan Conrad, manager of stategic programs development said.

However, utility figures on costs per installed kilowatt, while essentially within the ranges set by PSO, tended to be at the upper edges of these ranges. For two nuclear plants that would come on-line in 1993 and 1995, the cash construction costs were estimated to be $4,472 per installed kilowatt, and for the corresponding three coal plants expected to come into operation in 1991 and 1994, the cash construction costs were set at $2,090.

Fossil plant ordering blitz

While the two Black Fox nuclear units were part of the 5,811 MW of nuclear capacity cancelled during 1981, according to figures released by the Atomic Industrial Forum, during the same period electric utilities ordered 7,500 MW of new fossil-fired stationary electrical utility generating units, according to figures compiled by the American Boiler Manufacturers Association.

Fossil plant orders last year, up 47 percent over 1980, reflect more megawatts ordered than in any year since 1977. This suggests that, rather than there being a general decline in all orders for new plants, nuclear units are being substituted by fossil plants.

According to Russel Mosher of the ABMA, there were no fossil-fuel generation plant cancellations during the past 2 years.

The ABMA said, however, that it did not have a breakdown as to how many magawatts of the ordered 7,500 MW were coal plants, nor did it know the average size of the plants ordered, nor which utilities had signed contracts with fossil plant vendors.

FCC launches inquiry

WASHINGTON, D.C. — An inquiry to determine the best strategy for meeting the future needs of private land mobile radio users, such as utilities, has been launched by the Federal Communications Commission.

Commission officials say an inquiry is necessary because of the tremendous growth of private land mobile radio which, if continued at the projected rate, could result in a serious frequency congestion problem.

The inquiry has been broken into two major areas; the first is to deal with anticipated private and mobile requirements, and the second with possible sources of spectrum to meet those requirements.

Financial curbs . . .

from page 4

were assumed to rise to $37/barrel in 1985; to $41/barrel in 1990; and to $50/barrel in 1995.

Power plant capital requirements were determined by data supplied to DOE from electric utilities. Estimates that were received from the utilities on what plants they expected to build and operate in the future were part of the modelling used in the present report.

Another adverse effect that the EIA envisioned as a result of financial restraint was an increase in consumer costs by 1995. Using the April 1981 DOE study "The National Electric Reliability Study" to buttress its conclusions, the agency declared clearly that "Even though the relatively unrestrained building allowed in the base case (see table) would entail substantial capital outlays and produce reserves far beyond those required for system reliability, the resulting savings in operating costs could produce lower rates for electricity in the long run."

EL&P is looking for a new editor

Could YOU be the person we're seeking?

Electric Light & Power is looking for an engineer/communicator to join its editorial staff. Successful applicant will join EL&P's aggressive editorial team in covering transmission and distribution developments within and affecting the electric utility industry. Moderate travel required.

Applicant must have utility, consultant or manufacturer experience with T&D systems and equipment and possess strong writing/editing skills. Ability to understand and communicate difficult technical subjects is a must.

Location in EL&P's suburban-Chicago offices. Full program of company benefits.

Write: Editor, Electric Light & Power, 1301 S. Grove Ave., Barrington, IL 60010. Include resume and give salary requirements.

An equal opportunity employer

ELECTRIC LIGHT & POWER
1301 So. Grove Ave.
Barrington, ILL 60010
Telephone 312-381-1840

Robert J. (Duke) Kiesel
Group Publisher

Henry A. Petersen
Assistant Publisher

EL&P
SALES OFFICES

METROPOLITAN
NEW YORK
Bloomfield, N.J. 07003
41 Clover Lane
201-338-8524

NORTHERN NEW JERSEY
Bloomfield, N.J. 07003
41 Clover Lane
201-338-8524

UPSTATE NEW YORK
& NEW ENGLAND
(West Brookfield, MA) 01585
Ragged Hill Road
617-867-7797

PHILADELPHIA
(Plymouth Meeting, PA) 19462
Plymouth Plaza
215-825-4410

PITTSBURGH 15220
200 Fleet Street
Room #4045
412-921-7802

CLEVELAND 44114
815 Superior Ave.
216-696-4492

CHICAGO 60601
303 E. Wacker Dr.
Suite 218
312-938-2900

DETROIT
(Troy, MI) 48084
3221 W. Big Beaver, Suite 212
(313) 649-4330

LOS ANGELES 90035
1801 S. LaCienega Blvd.
213-559-5111

ATLANTA 30329
3515 Executive Park Dr., N.E.
404-633-5112

HOUSTON 77074
8515 Fondren Rd., Suite 104
713-981-4090

DALLAS
(Garland, TX) 75041
1700 Eastgate Drive
Suite 103
214-270-6461

ENGLEWOOD 80110
5680 S. Syracuse Circle
Suite 300
303-741-1068

Technical Publishing
a company of
The Dun & Bradstreet Corporation

James B. Tafel
Chairman

John K. Abely
President

Robert L. Dickson
Executive-Vice President

John R. Emery
Senior-Vice President

Calverd F. Jacobson
Vice President-Finance

Walter Harrington
Vice President-Controller

C8650- 4 3/17/80

Volume 60, Number 5
May 1982

0905 25 1830645 1 W JPK*
JOSEPH MCNALLY
CONGRESSIONAL INFORMATION
SERVICE INC
4520 EAST-WEST HWY-STE 800
WASHINGTON DC 20014

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

'Rate shock' crisis faces completed nukes

Dan Utroska
Associate Editor

It used to be that if electric company managers endured all the intervenor and regulatory delays, all the federally mandated design modifications, and the financial stress attendent upon building a nuclear power plant, then efforts would finally pay off as the plant became licensed and was put into rate base.

It could reasonably be expected that the higher capital costs of the nuclear plant would essentially be offset by fuel savings.

Today, if a nuclear plant makes it through all the federal construction and licensing reviews, it now faces a new difficulty: the growing political reluctance of public utility commissions to grant full rate base treatment for large base-load generating plants.

Alabama Power Company's Farley-2 unit is the first plant in recent time to be given a zero rate order after that plant went into service. In addition, both Long Island Lighting Company (with respect to its Shoreham plant) and Pennsylvania Power & Light (with respect to its Susquehanna Plant) are actively exploring alternatives to conventional rate base treatment. Philadelphia Electric Company's Limerick plants and Houston Lighting & Power's South Texas Project plants also have been mentioned as possibly coming in for less than full rate base treatment when they become operational. Assuredly, there will be others.

The impact of zero or partial rate base treatment by public utility commissions for large new plants around the country, caused by growing consumer resistence to higher electric bills, could be devastating. Electric companies with large construction programs are likely to be among those utilities in the shakiest financial condition; not being able to fully recover a large investment in new plant (or being able to recoup only some percentage of this), could knock the support out from under these companies.

Such state regulatory decisions therefore will be watched closely. Moreover, these negative rate orders carry potentially significant meaning for utility managers who are pondering the feasibility of continuing nuclear or other large base-load projects already in progress. Even under historical assumptions that full rate base treatment would be granted at or near in-service dates, utilities that have been constructing nuclear units have nevertheless been experiencing touch-and-go economics. Such calculations have already nudged out the

Continued on page 16

Tests confirm new breeder core design

IDAHO FALLS, IDAHO — The analytical methods used to redesign the reactor core of the proposed Clinch River breeder reactor are valid and the core will perform as intended, tests reportedly have confirmed.

The experiments were conducted at the Energy Department's Zero Power Plutonium Reactor (ZPPR), located at the Idaho National Engineering Laboratory here.

Originally, the core designed for CRBR — the socalled homogeneous core — contained plutonium-bearing fuel assemblies scurrounded by a blanket of uranium-bearing assemblies. The ZPPR experiments are said to have confirmed that the new core design — referred to as the heterogeneous core — could breed nuclear fuel with greater efficiency, improved operating safety, and reduced reactor fuel and control system costs (by an estimated $8 million).

The new "heterogeneous" core uses a different configuration of fuel elements than the "homogeneous" core. Also, some of the blanket assemblies in the new core are dispersed among the fuel assemblies.

"The results of these tests place this country in the forefront of breeder core design, and, as such, are key developments in the progress of the Clinch River project," DOE Assistant Secretary for Nuclear Energy Shelby T. Brewer said.

The assistant secretary noted that the experiments have confirmed that not only does the new core outperform previous designs, but it will operate with greater efficiency than even foreign designs.

The Clinch River plant is to be built in Oak Ridge, Tennessee, and is the nation's first large-scale demonstration liquid metal fast breeder reactor power plant. When operational, it will generate 375 megawatts, enough electricity to meet the residential needs of a city of 200,000.

The Clinch River breeder reactor project is the cooperative effort of the Department of Energy, the Breeder Reactor Corporation, and a number of electric utilities around the country.

Biggest solar field completed

Some of the more than 1500 solar collectors installed at Georgia Power Company's new general office building in Atlanta are shown. The installation, made up of more than 1.5 acres of trough-shaped, glass-covered panels, is the largest commercial application of solar collectors for space and water heating in the U.S. For a report on the current status of utilities' large-scale solar projects, see page 34. Photo: Richard Riley, Tampa, FL.

Power equipment demand to grow slower to '90, NEMA finds

WASHINGTON, D.C. — The need for generation and transmission and distribution equipment, while it will continue to grow over the next 2 decades, will do so at a declining rate, a new industry survey shows.

The "Eighth Biennial Survey of Power Equipment Requirements of the U.S. Electric Utility Industry, 1981-1990," reveals a greater deceleration of the growth of electricity demand and supply than has been shown either in previous biennial surveys or by other examinations of power industry requirements.

"There can be no doubt about the direction and the permanency of the alterations to the electricity industry in the U.S.," the introduction to the current survey reads. "The nation will carry on its functions and expansions using less electricity than heretofore thought possible. The price of electricity, the conservation ethic, and load management techniques have and will continue to slow the growth of the demand for electricity."

The biennial surveys are sponsored and published by the Power Equipment Division of the National Electrical Manufacturers Association.

Demand: 3 percent or less

The survey found that in 1982 electricity demand would increase 3.3 percent and would grow by an additional 3.5 percent in 1983. In the longer term, it was determined that de-

Continued on page 6

Nuclear utilities financial review dropped by NRC

WASHINGTON, D.C. — Declaring that there is no demonstrable link between the financial condition of a nuclear utility and the health and safety of the public, the U.S. Nuclear Regulatory Commission has decided to drop its requirement that electric companies planning to build nuclear power plants must be financially viable.

Before the March 30, 1982 amendments to NRC regulations, which eliminate financial reviews by the agency, an applicant for a nuclear construction or operating license had to show either that it had sufficient funds, or that there was a reasonable assurance that such funds could be secured, to cover applicable regulatory requirements. For construction permit applicants this meant that sufficient funds had to be present to cover construction costs and related fuel cycle costs. For operating license applicants, it meant enough money to cover estimated costs of operating the facility plus costs of permanent shutdown and maintenance in a safe condition.

"Any consideration of decommissioning funding should be eliminated from the present licensing process," a statement from the commission announcing the changes reads. "This does not discount the importance of decommissioning but places it in the context of an ongoing rulemaking proceeding. The NRC is expected to

Continued on page 6

Foreign Power Briefs

- **Korea Electric Power Corp.** has announced plans to build a medium-sized nuclear fuel fabrication plant within the next few years. Officials of the company said that invitations for overseas bids will be made late this year. Korea Electric hopes to complete the facility by the late 1980's. A government corporation, South Korea Electric is the sole power generator in Korea. Plans call for a plant capable of processing about 2,220 tons of enriched uranium annually. Currently, one nuclear plant is operating in the country and eight more are being built. Thirteen nuclear power plants are planned to be on-line before 1991.

- **Saudi Arabia** has signed a $25.9 million contract to buy three gas turbine-generator packages from General Electric Co., U.S.A. for the Jibal Fifa region near the Red Sea. When the units go into operation, scheduled for February 1983, the Saudi Consolidated Electricity Company for the Southern Region will assume ownership and operation. Each of the units will produce 27.47 MW.

- **The UK government** announced they have decided against testing the feasibility of burying radioactive waste in about 20 sites from Ayrshire and Galloway in Scotland to Worcesterhire. A government committee report that said the longer waste is stored, the more safely it can be buried, prompted the decision.

- **The first stage of a Soviet solar power station** that will be built near the village of Mysovoye in the Crimea will be commissioned in 1983. It will include a 75m high tower and a field of 400 automatically controlled concave mirrors. Full capacity of the station will be 5 MW from 1,600 mirrors. A pilot project with three moveable mirrors manufactured by the Ministry of Power Engineering of the USSR will be tried out first to prove the system. The station will have high capacity hot water and steam storage to keep the station operating in bad weather and at night.

- **Swaziland,** an African state between South Africa and Mozambique, is going ahead with plans for a controversial 20 MW hydroelectric power plant on the Lushuswana River. The dam, on the river, will cut the amount of power bought from South Africa to about half of the present level. Opponents of the project point out that it will also decrease the downstream flow of the river to less than 10 percent of its present volume, thus affecting the ecology of the area. Critics are also calling for the government to take advantage of its substantial coal reserves and build a coal-fired plant. The Swaziland Electricity Board has turned the suggestion down because it says the costs would be too high and the ecological impact on the area would be greater than the proposed hydro plant.

- **Enel, the Italian national electric utility,** expects to be the largest single consumer of coal on the international market, according to its Chairman, Francesco Corbellini. He told a London audience that delays in Italy's nuclear power program forced Enel to build coal-fired plants. Enel has helped a few small Kentucky coal producers organize a consortium to ensure a sales outlet. American coal delivered to Italy is about 35-50 percent cheaper than imported oil. Corbellini also called the plan to build coal-fired plants "transitional and contigent: this means that it is not expected to be followed by new coal programs in the '90s."

- **Japan's nuclear power plant construction program** will be revived this year. After a long stall, Chubu Electric Power Co. starts building its third reactor with 1,100 MW at Hamaika in March. Construction plans totalling more than 4,000 MW , are expected to be approved by the government's Electric Power Source Coordination Council. Largest plans are for two 1,180 MW plants from Kushu Electric Power Co..

- **The first discovery of geothermal steam in Canada** has prompted more drilling at British Columbia Hydro's Meager Creek geothermal site. A first well, drilled to 3,040m, found steam and temperatures higher than 200 degrees Celcius. Such temperatures, if combined with an adequate supply of pressure and water, could produce steam for generating electricity.

- **Jordan's fourth power project work begins** next year, following an agreement between a delegation from the Kuwait Fund for Arab Economic Development, the Jordan Electricity Authority and the Jordan Electric Power Company. Included in the project are plans for a 132 kV transmission network, rural electrification in the North and South of Jordan, and the installation of six new substations

- **Mexico** has turned into a revolving door for world leaders, as they try to win the competition to build $2 billion worth of nuclear reactors in Mexico. Among those visiting Mexican President Jose Lopez Portillo have been Canadian Prime Minister Pierre Trudeau, the King and Queen of Sweden and U.S. Commerce Secretary Malcom Baldrige. Combustion Engineering, General Electric and Westinghouse are after the contract, as well as companies in Sweden, Canada, France and West Germany. Formal bids to build the two 1,200 MW reactors at Laguna Verde were submitted last month. Mexico's Federal Electricity Commission is currently wading through the mounds of documentation. Although Mexico would like to make a decision by August, the presidential elections this summer might delay it to after the December inauguration.

C-E Studsvik has received a contract from Statens Vattenfallsverk, the Swedish State Power Board, to supply a compact nuclear simulator representing Forsmark 3, a 1050 MWe boiling water reactor. Reactor and turbine components, including an extraction steam system, heater drains, a suppression chamber and a moisture separator/reheater will be represented. The simulator will also have the capability to display the axial power distribution of any individual fuel channel disturbed by an adjacent control rod. The unit is scheduled to be delivered later this year.

In This Issue

Editorial 4

Financial constraints have prompted electric utilities to employ innovative strategies to meet future power demands. A Special Report 8

The Edison Electric Institute has submitted its report on PCBs to EPA showing complete removal would cost $10 to $20 billion. **T/D** 23

The demise of the federal government's solar power central receiver research program is being protested by a group of western utilities. **E/G** 34

Political bickering is making chances for action on the Clean Air Act this year poor. **E/G**. 39

Use of coal-water mixtures as a substitute fuel for oil is beginning to look promising. **E/G**. 47

The shortage of ways to dispose of old PCB-contaminated capacitors is easing as new options are approved by EPA. **T/D** 51

Reader Service 55

New Products. 58

New Literature 62

Advertisers' Literature. 66

Personnel 68

Regulatory Review. 70

Management Methods 74

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1, the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

PG&E hires Bechtel for Diablo Canyon

SAN FRANCISCO — Bechtel Power Corporation has been hired by Pacific Gas & Electric Company to act as project manager for the completion and licensing of the Diablo Canyon nuclear plant.

According to PG&E chairman Frederick W. Mielke, Jr., Bechtel will be responsible for having the company's low-power operating license restored for operation of unit 1. The NRC had granted the company such a license on September 21, 1981, but suspended it in mid-November when problems were discovered in the reactors' construction design. Bechtel is also charged with securing a full power license for the plant.

In addition, the consulting firm will oversee construction of unit 2, which, as of December 31, 1981, was about 90 percent complete. The firm will also provide start-up engineering and construction support needed to bring both units into commercial operation.

Diablo to 'stabilize' bills

The announcement by PG&E that it had hired Bechtel follows a decision by the staff of the Nuclear Regulatory Commission to approve Teledyne Corporation to conduct the design verification program for Diablo Canyon. Mielke said he was pleased with the decision because "the reverification program now can go forward with a minimum of delay."

Mielke added that he shares customers' concern about the burden of this winter's high utility bills. "Getting the Diablo Canyon power plant safely and successfully on line will do more than any single thing the company can do to help stabilize electric bills, minimize our dependence on costly oil and natural gas, and provide our customers with a safe, reliable electric energy supply for the years to come," he said.

Hand delivery saves

CHARLOTTE, NC — Officials of Duke Power Company estimate they are saving more than $7,000 per month from the use of hand delivery of monthly bills.

The company currently is hand-delivering bills in seven cities. The bills are hung on doors because postal regulations prohibit use of mail boxes for other than U.S. mail.

The cost of hand-delivery works out to $0.11 each. The cost of presorted U.S. mail is $0.17 each.

Duke uses high school and college students to deliver the bills because of their eagerness and interest in only part-time work. If they prefer, customers can still receive their bills by U.S. mail.

Duke began a pilot hand-delivery program in 1976. The pilot program showed that hand-delivery was only economic in densely populated urban areas.

Utilities employ innovative strategies to satisfy future power demands

Uncertainties today as to whether to emphasize "fundamental problems," or to highlight financial indicators that are trending upward, characterize the internal conflict of an industry that feels its traditional infrastructure creaking under the strains of new financial realities. The seriousness of the industry's concerns, therefore, is more a matter of focus and perspective than of objective consensus.

Dan Utroska
Associate Editor

The demand upon electric utilities to supply reasonably priced, reliable energy is not only causing companies to identify innovative financing techniques to build traditional base load generating plants, but is prompting some companies to rethink the entire traditional approach to providing electricity.

Given an estimated aggregate financial requirement on the electric utility industry of $338 billion during the 1980s to construct new plant, investment banking firms are scrutinizing the implications of new tax laws, hoping to come up with innovative financing approaches like the debt-equity swap method developed by Solomon Brothers (see box) which permits an electric company to retire bonds, issue new stock, and improve its debt-equity ratio, while sending a healthy chunk of fresh income directly to the bottom line on the company's financial statement.

In other cases, investment houses not only are joining the utility chorus for greater rates of return, higher revenues, and inclusion of construction work in progress in the rate base, but are arguing the necessity of reduced load growth, higher pricing mechanisms, and avoidance of nuclear power.

Additionally, financial analysts are beginning to comtemplate how the electric utility industry, moved by financial constraints, will be forced to change over the next 10 years. "With the industry in poor financial condition, many utility managements and boards of directors, (in order to) protect investors, may seriously question undertaking the capital and operating risks of adding new generating capacity," Daniel Scotto of Standard & Poors Corp. remarked recently before the Financial Analysts Federation Bond Seminar in New York. "This could lead to a host of new financial structures and generic issues to be addressed over the next decade."

Scotto, who is an assistant vice president for electric and water utility ratings, reflected a sentiment at the meeting which seems again to be ascendent: that future capacity additions may not be under state jurisdictions. "Instead," he said, "the production of electricity could be moved to the federal level, under wholesale corporate structures, or even, completely deregulated. Given the current rulemaking hearings on construction work in progress by the Federal Energy Regulatory Commission, prospects for better returns may actually be greater at the federal level."

For their part, certain electric utilities, — and especially those that face capacity additions in the future — are opting for solutions that substantially revamp the more conventional ideas of having the electric company be the central station supplier of power. Arkansas Power & Light Company, for example, is contemplating becoming the main developer, owner, and operator of cogeneration facilities that will produce steam for its industrial customers while creatively providing electricity for its regular service area. The utility envisions that it will be able to back out of electricity production appreciably while doubling its revenues by 1985.

And in a separate action, AP&L, in coordination with the Alliance to Save Energy, is looking into the feasibility of becoming a third party financier of energy conservation in its service territory. Other utilities across the nation are carefully eyeing developments here to see if they have merit.

Utility-industry partnerships

If some electric companies had not already begun to redefine their roles as suppliers of electricity, industrial customers, who also appear increasingly worried about utility construction financing difficulties, are now openly advocating new initiatives, such as corporate compacts in electricity generation.

Industrialists, who see themselves as involuntary subsidizers of electricity to residential and commercial users, believe that not only are these "payment transfers" approaching a limit, but higher rates to all classes of customers are rapidly reaching a political boundary. If the rate of recent utility revenue increases dampens, industrialists fear that capital-strapped electric companies, responding to reduced construction programs, will be forced to discourage new demand.

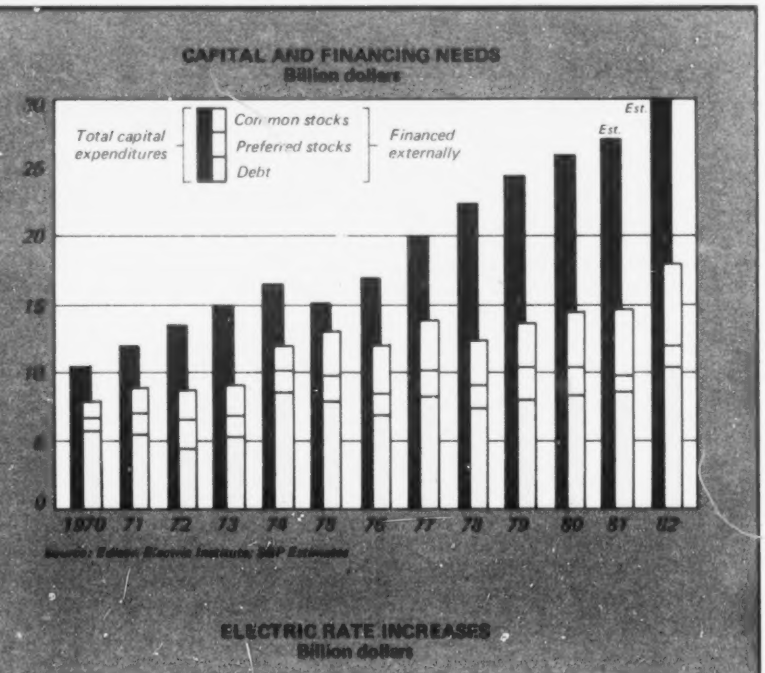
In a move at self-survival, some industrialists therefore are calling for the serious consideration of power partnerships. "There is little else left to try but to solve the problems together by forming financial alliances between utilities and industry," Herbert J. Edwards, senior vice president of Ebasco Business Consulting Co. said.

Noting that conventional financing and pricing of generation tends to "frontload" the cost to the ratepayer, (because kilowatt-hour costs increase precipitously as the plant is included in rate base), Edwards said that alternatives would levelize these costs over time. "This means that the economics of self-generation, as well as cogeneration, may be turning around. Compared to the uncertain availability of power, even at new-resource costs, industrial investments in power supply will be more economic as time goes by," he said.

The success of such corporate compacts depends upon the parties identifying innovative financing techniques as well as new technologies. Also, many traditional barriers have to be overcome. "If these barriers cannot be surmounted," Edwards said, "utilities face not only a declining industrial sales base and lower efficiencies; they face obstacles to economic development of their service areas as well."

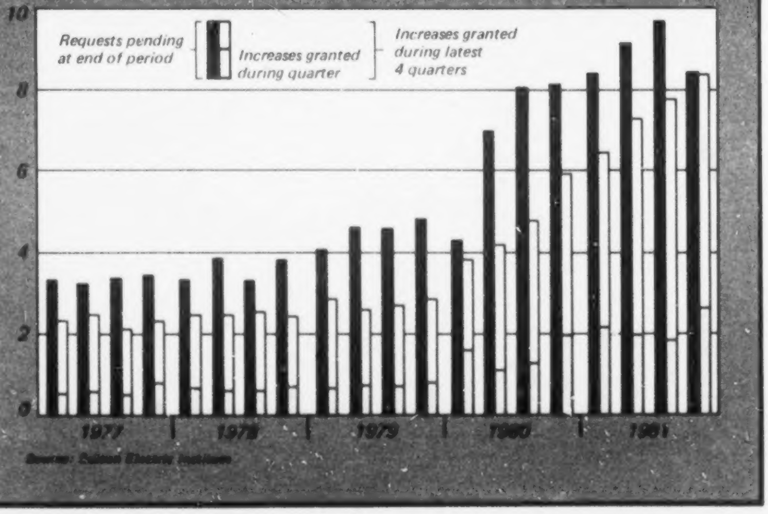
He concluded, "Should it come to pass that industrial firms are forced by circumstances to provide their own power, keep in mind that timing is vital. In today's world it takes 10 years to get a major generating unit built. In 10 years we could all learn Japanese like a mother tongue."

CAPITAL AND FINANCING NEEDS
Billion dollars



Source: Edison Electric Institute; S&P Estimates

ELECTRIC RATE INCREASES
Billion dollars



Source: Edison Electric Institute

Financial "problem": how severe?

What seems most to characterize discussions about the financial condition of the electric utility industry is the gaping disparity of views over whether there is or is not a crisis — or even a problem. "There are a whole lot of serious people who say there is no problem at all," Howard F. Perry, Utility Policy Advisor at the Department of Energy said. "There are a lot of other serious people who say the electric system is going to hell in a handbasket."

Perry, as head of DOE's national electric policy project, will, over the next few months, attempt to find out where the truth lies. "Sorting this out is not an easy task, but we are going to try to do it this year." (see EL&P, April, 1982, page 1).

In addition, the National Association of Regulatory Utility Commissioners is in the process of writing a report on its findings regarding the financial condition of the electric utility industry. Originally expected to be completed for the association's annual meeting in November, 1981, release of the report is now targeted for sometime in July, 1982.

According to Standard & Poors' Kenneth M. Alterman, although average *authorized* returns have increased from 12.5 percent in the early 1970s to 15.5 percent in 1981, recent *earned* returns on equity have been only in the area of 11 percent. This compares with 12 percent in 1970. In

Duke Power reaps benefits from debt-equity swap

Duke Power Company appears to be one of a growing number of businesses that are turning to the debt-equity swap to retire discount debt, while issuing new shares of stock, and improving the quality of earnings.

This innovative financing method, if it is properly structured, can result in a transaction that is tax free, and although the technique reportedly is still without an actual tax ruling by the Internal Revenue Service, it is being given the go-ahead by numerous corporate attorneys.

In essence, an investment banking firm ventures into the market to buy up a company's existing low-coupon bonds, sometimes offering a price slightly over market to induce sales. Acting as a principle in the transaction, the investment banking firm now calculates how many shares of a company's stock will be required to offset the retired debt plus various costs that arise from the deal.

The investment banking firm now swaps the retired debt with the company for the new stock issues which the banking firm then turns around and sells on the open market. The principle benefit to the corporation is that it is able to send directly to earnings the difference between the face value of the retired securities and the cost the company paid for them. The company is therefore able to avoid the taxes it would have had to pay if it retired its outstanding debt on its own.

The principle features of the Duke Power transaction are outlined in the table. Of paramount interest here is the tax free gain of $48.3 million that was realized by the utility. The swap deal was concluded during the first week of January, 1982.

According to Duke Power's William H. Grigg, the swap increased the company's common equity component of capital structure from 39 to 41 percent, while long-term debt declined from 48 to 46 percent.

Further, the effective book value of the newly issued shares was $32.68, 137 percent of the 1981 year-end book value. Grigg, who as senior vice president at Duke deals with legal and financial matters, said this resulted from the fact that no shares were issued on the incremental gain that resulted from the swap and which is entered on the books as equity.

> ***"When it comes to raising new equity capital in the marketplace without equity dilution, this may be the only game in town."***

The benefits that accrue to the company are a stronger capital structure which reduces the financial risk of all of the company's securities. This makes new debt and common equity capital more readily available at lower cost than would otherwise be the case.

DUKE POWER COMPANY DEBT-EQUITY SWAP

	(in millions)	
Debt retired (first mortgage bonds)	$119.9 face amount	
Average coupon of bonds retired	8%	
Average market price of bonds	58.9% of face amount	
Gain on bonds (carrying value less market price)	$ 48.3	
New common shares issued	3.7	
Market value of shares ($20.375 per share less $.66 underwriter's discount)	$ 73.5	
New common equity (market value of shares issued plus gain on bonds)	$121.8	
Book value of new shares	$ 32.68 per share (137% of book value per share at 12/31/81)	
Change in Book Value	from $23.83 to $24.19 per share	
Change in Capital Structure:	Before	After
L/T Debt	48%	46%
Preferred	13%	13%
Common	39%	41%
	100%	100%
Embedded Cost of Debt:	At 12/31/81	9.34%
	Effect of Exchange	.06
	As Adjusted	9.40%

In addition, common equity is increased without the dilutive effect of selling new shares at prices below book value. This is expected to result in higher earnings per share and fewer dividend payments in the future. A corresponding improvement in cash flow is also seen.

Finally, the tax-free nature of the exchange provides new capital at far less cost than if capital were raised through retained earnings, where income taxes take about one-half of earnings.

For all its advantages, the debt-equity swap does not affect the company's need to raise new capital. Because no cash is involved in the exchange, the company's future capital requirements remain the same. "Recapitalization is what this is," Grigg said.

There are some potentially negative impacts here. First, the swap has no immediate effect on rates. However, the stronger capital structure that results from the swap can be interpreted as requiring lower allowed return on equity because of the reduced financial risk. "Our analysis showed that, in fact, some reduction in allowed return on equity can be made without taking away all of the earnings per share benefit of the exchange," Grigg said. "The risk is that the allowed rate of return might be reduced below the 'break-even' point for the cost of service, thereby penalizing the equity investor."

Grigg said that Duke believed that taking such a risk was reasonable. "The alternative," he said, "was either a certain further decline in fixed-charges coverages or a certain further dilution of shareholders equity through the sale of common shares at prices well below value."

Another risk encountered when a regulated company engages in such a debt-equity swap relates to how the gain is accounted for. Grigg said that unless the gain is recognized as an extraordinary item of income and carried to retained earnings, the benefits of the transaction are lost. "In Duke Power's case, that risk was minimized by obtaining prior approval of our regulatory authorities of the proposed accounting treatment."

"In short, this swap made good business sense to us and we were willing to accept the rate of return risk," Grigg concluded. "Clearly, it may not fit the needs of every utility...and it requires careful analysis. But when it comes to raising new equity capital in the market place without dilution, it may be the only game in town."

1974, Alterman said, the spread between average authorized and earned returns on equity was 190 basis points; currently it is more than 300 basis points.

In addition, while earned returns on equity have remained virtually unchanged during the decade, he said the quality of earnings has deteriorated noticeably. Also, allowance for funds used during construction (AFUDC), as a percentage of net income, is currently near 50 percent, contrasted to 12 percent in 1970.

"This growth in the portion of non-cash earnings reflects the quantam rise in the cost of new generating capacity, extended delays in construction, escalating costs of capital, and the growing percentage of funds invested in non-revenue producing construction work in progress," Alterman said.

Twelve years ago, he said, the average electric utility was rated "AA." Today, the industry's "center of gravity" is "A-," and is trending toward "BBB+."

And according to the Edison Electric Institute, the inadequacy of equity returns is underscored by the gap that exists between these returns and the cost of new debt. Using 1980 figures (the most recent available from EEI), new long-term debt was issued at interest rates averaging nearly 14 percent. Comparing this to a 1980 earned return on equity of 11.4 percent reveals a negative risk premium of 2.6 percent. This negative risk premium was realized, EEI said, while the equity markets were demanding just the opposite — a 3 to 4 percent premium return differential over long-term interest rates.

Despite some recent positive signs, "there are still fundamental problems for the electrics," Alterman concluded.

Yet, uncertainties today over whether to emphasize these "fundamental problems," or to highlight financial indicators that are trending upward, characterize the internal conflict of an industry that feels its traditional infrastructure creaking under the strains of new financial realities. The seriousness of the industry's concerns, therefore, is more a matter of focus and perspective than of objective consensus.

Some healthy signs

"For the first time since the electric utility industry's financial interlude during 1976-78, things are looking up," S & P's Daniel Scotto said. He noted that many equity analysts are pointing to higher allowed returns on equity, more cash flow from the 1981 tax act, completion of major construction projects, especially nuclear, and declining spending and less reliance on common stock financing.

Yet, Scotto said, "The industry is far from being out of the woods financially. When an industry is flat on its back, things are generally looking up."

The Edison Electric Institute, on the other hand, regularly concentrates its focus on the more threatening aspects of the future. "If the electric power industry falters, the nations economy falters as well," EEI's president William McCollam Jr., told the New York Society of Security Analysts recently. "The industry's less-than-robust financial health puts its ability to provide that power at risk ....If we are unable to complete construction schedules for vitally needed plants, it will not be long, perhaps later in this decade, most certainly early in the next, when electric power shortages can be expected to constrain the economy, with resulting adverse effects on employment, on the U.S. ability to compete in the world markets, and on the national security."

And in testimony late last year before a financial status inquiry committee of the National Association of Regulatory Utility Commissioners, H. L. Culbreath, chief executive officer at Tampa Electric Co., representing Edison Electric Institute member companies, referenced the institute's calculated negative risk premium. "This negative return will not be accepted on a continuing basis," he testified. "At some point equity investors will respond by investing less in utility securities."

Utility stock sales brisk

Not only has a recent Department of Energy report challenged assertions that financial constraints on power plant construction are likely to lead to power shortages through the 1990s, (see EL&P, April 1982, page 4), but electric utility stocks out-performed the overall market by a wide margin in 1981. In addition, the data show that utility stocks have held up extremely well in the early months of 1982, doing so under generally poor market conditions.

"For the first time in many years, the Standard & Poors index of electric utility stocks in 1981 was a better performer than the S&P 500 index," S&P's business magazine The Outlook reported in early March.

"The electric utility index posted a gain of 7.9 percent and ranked 33 out of 110 S&P stock groups, while the '500' declined nearly 10 percent. In terms of total returns (price change plus dividends), the performance disparity is even greater. The total return of the electric utility index amounted to 21 percent, versus a negative 4.8 percent return for the '500'."

The Outlook also concluded, "The price gains have been recorded despite an uptrend in interest rates."

There may be components within this healthy total utility stock return

Continued on 10

Future power demands ... from previous page

that appear stronger than they actually are, however. S&P reports that in many cases of utility operations, earnings did not justify corresponding dividend boosts. "As a result, the average payout ratio (dividends as a percentage of earnings) has risen to levels not seen since the early 1950s," The Outlook reports. "The ratio for 1981 approximated (the) 1980s' 74.6 percent, up from 67 percent 5 years ago; the peak of 78.6 percent was reached in 1951. The ratio could edge higher this year (1982), with dividends rising slightly more than the 5 percent increase in earnings we (at S&P) are estimating."

Whether these "pumped up" dividend components of total returns are sufficiently inflated to constitute a future liability for electric companies, and whether this practice is sufficiently wide-spread in the industry to appreciably undercut recent measured advances in total returns, is at present unclear.

Electric utility optimism

While various industry observors are examining earned returns on equity over the past year or so and shaking their heads in despair, J. H. Ranniger, a vice president at Public Service Company of Colorado, has taken heart from such recent advances in electric utility financial indicators. In fact, Ranniger sees such a confluence of positive economic, regulatory, and corporate factors that he felt moved to stand before industry colleagues recently and declare, "That ball of fire on the horizon which some viewed as the setting sun for the utility industry can now be viewed as the sunrise, not the sunset."

And, he added, "This is a time for optimism. The darkest hours are behind us."

Challenging figures presented by others, Ranniger said that in 1981 the return on equity earned by the electric utility industry had advanced toward the 12.5 percent level. He noted, "There is still a long way to go, but the trend is in the right direction." The PSCo executive said that many of the difficulties that had arisen in the 1970s, were beginning to be resolved and further remedies were being identified that would work to strengthen the industry in the 1980s.

Ranniger mentioned reduced regulatory lag time, the increase in authorized rates of return, the fact that some 23 jurisdictions, including the Federal Energy Regulatory Commission, now use some form of forecasted test years for the calculation of rates, and that some 20 percent of the regulatory jurisdictions now specifically incorporate an attrition allowance into their revenue calculations.

He observed that authorized revenue increases have been "greatly increasing" in recent times, and that in 1981 dollars aggregate revenues have gone from $2 billion in 1971 to $7.7 billion in 1981. "In the same 10 year period, the ratio of revenue increases granted to that requested bottomed out in 1976 when only 51.5 percent of that sought was granted. That ratio has increased tc an estimated 69.1 percent for 1981," he said.

The market-to-book price ratio of utility stocks also has shown marked improvement in recent months, Ranniger observed. He noted that the ratio has improved from 75 percent in January, 1981, to an estimated 81 percent in December, 1981. "Again," he noted, "there is a long way to go, but...this trend is in the right direction."

With respect to rate base treatment, Ranniger's research found that 22 state jurisdictions and the District of Columbia use year-end rate base, whereas some years ago, average rate base was in much more widespread use.

He noted that most electric companies have undertaken stringent cost control programs and have launched educational initiatives to put their respective cases before regulators, the federal government, and the public.

Finally, the increasing use of cost-based rate design is seen to inherently provide not only equitable treatment of all customers, but the reshaping of utility load characteristics so as to minimize overall costs of rendering service. "It can," Ranniger said, "provide for the charging of customers who create undue cost burdens on the company, and can...provide for the minimization of the construction of very expensive new generating facilities."

Alternative approaches weighed

Very expensive new generating facilities is one of the prime reasons underlying the growing attention being paid by electric utilities to cogeneration. "In light of the economic and tax motivations for cogeneration and the impetus provided by the Public Utility Regulatory Policies Act of 1978, the movement towards cogeneration is gaining momentum and substance," said Kenneth F. Seplow, vice president of Kidder, Peabody, & Co. Speaking at the recent Energy Technology Conference in Washington, Seplow noted that electric company responses have varied from reluctant, mandated participation to positive and aggressive action, such as that exhibited by Arkansas Power & Light.

"Though the reactions differ across the country, most electric utilities are coming to terms with PURPA, and by extension, cogeneration," Seplow said. He noted that the displacement by cogeneration of 10 percent of today's industrial electric usage has been calculated to require $15 to $30 billion of capital, depending on the methods employed. Seplow cited various economic reasons why industrial companies, although unlike electric utilities in many respects, have been generally disinclined to retrofit to cogeneration facilities. But he noted that newly constructed industrial facilities have been incorporating cogeneration. Although these projects tend to be small and relatively few — "only a trickle now," he said,—the trend is here. "It could readily grow into a stream which in a decade could produce the $15-$30 billion of aggregate capital investment mentioned earlier as a possible benchmark."

"Cogeneration is a new diversified business in which existing energy enterprises can build on old strengths — knowledge of markets and energy economics and mechanics," Seplow concluded. "Investment in cogeneration can be a good capital investment. It affords debt leverage and tax advantages. It has some of the stability of the electric utility business without the same kind of adverse regulation. In effect, under PURPA, it benefits from regulation of the electric industry, but permits the investor to operate without a declining rate base or a rate of return limitation."

Utility as third party financier

Third party financing of conservation is another alternative approach to financing new base-load construction and here, as in cogeneration, Arkansas Power & Light is emerging as an industry pacesetter. Selected by the Alliance to Save Energy to investigate the feasibility of a major utility assisting its customers with energy conservation investments, AP&L, in coordination with the Alliance, is looking at some 20 standard industrial code (SIC) catagories in its service area to determine the nature of these potential commercial and industrial investments, and the expected payback over a specified time period.

When the Alliance to Save Energy received a grant of $428,000 from a large private foundation to examine this question, it began scouting around to determine which utility might be most enthusiastic about actually implementing load reduction methods in its service area. After reviewing numerous electric companies, the Alliance settled on AP&L. "We were persuaded that AP&L was truly committed to energy conservation," Robert J. Rauch, an attorney and legal consultant for the Alliance said.

There are 3 major types of the third-party financing of energy conservation: leasing, share-the-savings plans, and energy service contracts. Each has advantages and disadvantages for different types of energy users and presents a different set of tax and legal risks for the third-party investor.

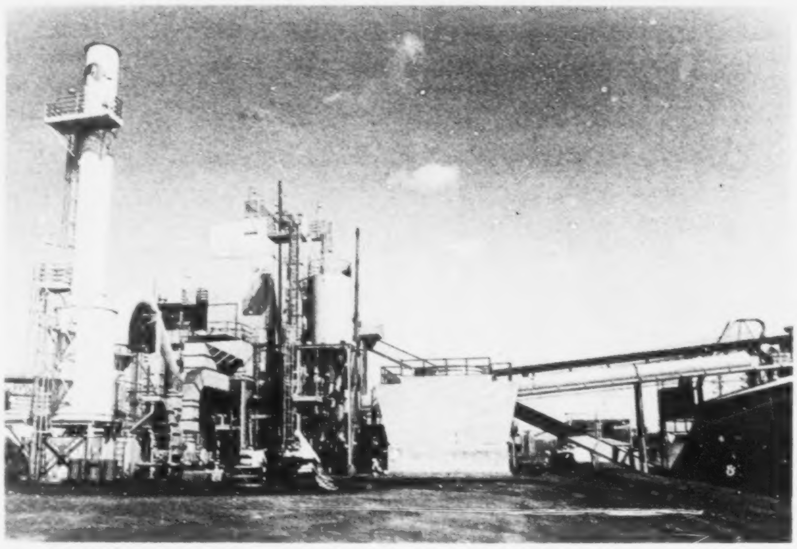
And in addition to utilities getting directly involved in financing, there are other important roles they can play, some of them in participation with private investors. An electric company might provide low-interest loans to private groups that are trying to put together third-party financing of conservation strategies. This could aid those groups that are able to put certain equity money up front but have to borrow the rest to get going.

Also, certain electric utilities could form a financial pool for insurance purposes. Such a pool, Rauch explained, could act as an economic safety net for those energy conservation enterprises that fall short of projected goals. Even with professional engineering analyses of specific energy conservation projects, potential investors might be skittish about the ultimate realization of estimated energy savings. With electric companys' underwriting possible shortfalls, investor participation in these enterprises could be enhanced substantially.

"We think that utilities' participation potentially is very important because third-party financing of conservation will make up a sizeable portion of the total conservation during the 1980s," Rauch said.

Described as the first in-depth study conducted to assist commercial and industrial customers with energy conservation, the AP&L/Alliance project has stimulated the interest of numerous electric companies. Participants in the study say they hope the findings of the research effort, which are expected to be released sometime in November, 1982, will have an influential impact on those utilities that currently believe encouraging conservation is not an electric company function.

Almond nutshells fuel new power plant near Sacramento



This 8,500 kW power plant fueled by almond shells delivered 1.9 million kilowatthours of electricity to Pacific Gas and Electric Company in its first month of operation. Imotek, Inc., a San Francisco engineering firm, owns and operates the plant, which is located at the California Almond Growers Exchange near Sacramento.

SACRAMENTO, CA — A new cogeneration plant fueled by almond nutshells has delivered 1.9 million kilowatthours to Pacific Gas and Electric Company in its first full month of operation.

Located at the California Almond Growers Exchange, the plant is owned and operated by Imotek, Inc., a San Francisco engineering firm. In addition to producing electricity, the plant produces steam for use by the almond growers' processing facility and by a neighboring industrial plant.

Malcom A. MacKillop, PG&E senoir vice-president said that the utility is committed to renewable resources. "Last year," he said, "we increased our commitment and now plan to have almost 60 percent of our new generation capacity in the 1980s come from these resources."

Projects total 884,523 kW

Since its cogeneration program began in 1980, PG&E has negotiated power purchase contracts or other firm commitments for projects that will total 884,523 kW in generating capacity when they are complete.

Of PG&E's contracts, cogeneration and solid waste projects account for 409,800 kW; wind farm projects, 382,800 kW; small hydro power plants, 81,300 kW; and miscellaneous projects the remainder.

PCB elimination cost set at $10-20 billion

WASHINGTON — It could cost the electric utility industry from $10 billion to $20 billion to completely get rid of PCBs, according to a report recently submitted to the Environmental Protection Agency by the Edison Electric Institute. An EPA-supplied summary of the EEI report suggests that current EPA regulations on PCB-containing equipment be left largely unchanged.

The EEI report is part of a review of PCB regulations ordered last year by the District of Columbia U.S. Court of Appeals. The court ordered the review in response to a suit brought by an environmentalist group, the Environmental Defense Fund, challenging EPA's treatment of utility PCB equipment. EPA regulations currently define such equipment as an acceptable "totally enclosed" use of PCBs and set the regulatory cutoff at material contaminated with 50 ppm or more of PCBs. The appellate court said that EPA's justification for these definitions was insufficient and ordered it to issue new regulations by this coming August based on better supporting studies. The EEI report is to constitute part of the improved backup material for the new regulations.

An EPA spokesman says the EEI report, submitted in late February, was a big step toward getting out the new proposal, which should be published in the Federal Register about now. (The proposal was due in April, the final regulation in August.)

EEI's analysis of the cost of replacing all equipment contaminated with more than 50 ppm PCBs is shown in the tables. The raw costs are shown in the first table and the incremental costs in the second. The incremental costs are the actual additional costs that would be imposed on utilities by a requirement to phase out PCB equipment over various time periods. These are less than the costs shown in the first table because some of this equipment would be phased out and replaced in the normal course of events

The report says that out of the total of 24 million pieces of equipment in the utility industry, 22.1 percent contain fluid with more than 50 ppm PCBs, and 12.8 percent have fluid with more than 500 ppm. Askarel transformers and PCB capacitors account for 93 percent of the equipment in the greater-than-500-ppm category.

Enough capacity

EEI cites estimates from the National Electrical Manufacturers Association that there is sufficient manufacturing capacity to replace askarel transformers in service with "low flammability" substitutes in about 5 years. "Such production estimates," says the report summary, "are based upon the assumption that utilities would be willing to accept currently available low flammability technology as a replacement for askarels, and would also make whatever changes are necessary in system engineering or equipment siting to accommodate the increased risk of fire."

For PCB capacitors, EEI estimates that the capacitor manufacturers could replace all utility-owned PCB units now in service with acceptable substitutes in 8.4 years, if production capacity were increased 50 percent. However, there are many PCB capacitors outside the utility industry, EEI notes, and a nationwide replacement program would take considerably longer.

It would take about 3 years to replace all the contaminated mineral oil equipment in service, says the report. Transformer manufacturers are currently turning out approximately 1.3 million units a year, at 60 percent of production capacity, says EEI. Replacement oil could also be supplied in about the same time frame.

Disposal facilities for contaminated materials could be a problem though, the report warns. If the two currently licensed incinerators did nothing but burn askarel from utility-owned transformers 20 hours a day, 350 days a year it would take 5.3 years to get rid of it all, says EEI. Everybody's askarel would take 17.6 years. Mineral oil from utility transformers containing more than 500 ppm PCBs would take 3.4 years, according to the EEI analysis. The report notes that some "destruction" processes have been approved by EPA, but adds, "Since these processes have received only preliminary approval to operate, it is impossible to determine the commercial scale costs of these processes or the ability of these processes to significantly impact the time required to dispose of PCB-contaminated oil.

Only one incinerator is licensed to burn shredded capacitors, the report notes, and it would take it 19 years to handle existing utility-owned PCB units. If the second unit is licensed, the job could be done in 4.1 years.

The two incinerators would require 12.5 years to burn the 730 lb of contaminated mineral oil in utility-owned equipment. The report concedes that oil with less than 500 ppm can be burned in utility boilers, but it says that use of this option is limited: "Despite the relatively low conversion costs (one utility recently completed conversion for approximately $72,000) required to prepare a utility boiler for incineration, only 6 utilities of the 100 largest utilities sampled are currently doing so, and they indicate no intention of offering this service to other utilities...Overall strong public resistance has severely restrained the use of this disposal alternative."

As mentioned, the total cost of indentifying PCB equipment, replacing it, removing the old equipment, beefing up fire protection capability, storing PCB materials, and disposing of the PCBs is estimated by EEI to be in the $10 billion range.

As an alternative to complete replacement, equipment could be rinsed with a solvent to get contamination below 50 ppm and refilled with clean fluid. That option, says EEI, would cost $8.7 billion.

Another regulatory option would be to require inspection and containment of potential spills from utility PCB equipment, in the form of dikes, retention ponds, etc. EEI's analysis of the costs associated with this option are shown in the third table.

The EEI report also analyzes the leak potential from utility PCB and PCB-contaminated equipment, as shown in the fourth table. Leak rates and amounts were extrapolated from PCB spill reports stemming from the interim measures program put into effect after the appellate court ruling last year.

As shown in the table, askarel transformers and PCB capacitors account for 99.75 percent of the PCBs that may be leaked, using the upper bound numbers. "The remaining annual PCB losses (0.25 percent) from mineral oil equipment," says the report summary, "are likely to be leaked in extremely small quantities (average leak quantities range from less than one one-hundredth of one tablespoon to one-tenth of one tablespoon; the median volume of mineral oil leaked or spilled is less than one gallon, of which 0.06 ounces are PCBs.)"

Regulatory action aimed at preventing leaks or spills of mineral oil with more than 500 ppm PCBs would only prevent a total of 230 lb of PCB from entering the environment every year, says the report. Prevention of leaks from oil with 50-500 ppm would only eliminate 508 pounds per year of PCBs.

SUMMARY OF EQUIPMENT PHASE-OUT COSTS
(In 1981 Pre-Tax Dollars)

Cost factor	Askarel transformers	Mineral oil transformers containing ≥500 ppm PCBs	PCB capacitors	Mineral oil equipment containing 50-499 ppm PCBs
Identification[a]	–	$6,100,000,000	–	$ 6,400,000,000
Equipment replacement	$ 552,000,000	190,000,000	$ 806,000,000	2,660,900,000
Removal/ installation	495,000,000	108,000,000	381,000,000	1,083,300,000
Disposal[b]	169,000,000	160,000,000	260,000,000	478,000,000
Total	**$1,216,000,000**	**$6,558,000,000**	**$1,447,000,000**	**$10,622,200,000**

a. If testing were not done or if all mineral oil equipment were required to be taken out of service, the replacement, removal/installation, and disposal costs would increase by a factor of 10.

b. Does not include costs of interim storage.

INCREMENTAL COSTS OF 2, 5, 10, AND 20 YEAR
EQUIPMENT PHASE-OUT COSTS
(In 1981 After Tax Dollars)

Phase-out period	Askarel transformers	Mineral oil transformers containing ≥500 ppm PCBs	PCB capacitors	Mineral oil equipment containing 50-499 ppm PCBs
2 Years	$832,000,000	$3,100,000,000	$968,000,000	$5,900,000,000
5 Years	736,000,000	2,900,000,000	830,000,000	5,500,000,000
10 Years	590,000,000	2,700,000,000	622,000,000	4,800,000,000
20 Years	346,000,000	2,300,000,000	277,000,000	3,600,000,000

ESTIMATED CONTAINMENT COSTS FOR PCB PROGRAMS
TO CONTAIN SELECTED PCB-CONTAMINATED MINERAL OIL EQUIPMENT
($ Billions)

			Water accumulation costs[b]			
Type of equipment	Identification costs	Dike construction costs	Bi-weekly inspection	Weekly inspection	Retention ponds/ tanks	Total cost
Pad-mounted PCB-contaminated mineral equipment	$1.4	$1.0	$2.4	$4.8	$1.3	$3.7-$7.2
All pad-mounted PCB-contaminated mineral oil equipment and 75% of PCB-contaminated pole-mounted mineral oil equipment[a]	$6.4	$2.3	$9.2	$18.4	$5.0	$13.7-$27.1

a. Assumes that 25% of pole-mounted units are located in areas which cannot be diked.

b. Assumes inspections for the estimated 20 year remaining useful life of the equipment.

ESTIMATED TOTAL POUNDS OF PCBs
LEAKED/SPILLED PER YEAR AND AVERAGE LEAK
QUANTITY BY EQUIPMENT TYPE

Equipment	Total PCBs leaked/spilled per year (lbs)	Average quantity of PCBs leaked/spilled per leak/spill (lbs)
Askarel transformers[a]	178.9 - 20,448.0	0.56 - 64.5
PCB capacitors	43,159.2 - 369,251.0	2.0 - 17.1
Mineral oil transformers	7.2 - 825.7	0.00004 - 0.005
Voltage regulators	0.15 - 4.9	0.0001 - 0.004
Oil-filled circuit breakers	0.04 - 50.9	0.000002 - 0.003
Reclosers[b]	0.002 - 6.6	0.0000001 - 0.0004
Switches (e.g., sectionalizers)[b]	0.051 - 79.7	0.000001 - 0.0019
Total	**43,345.5 - 390,666.8**	

a. Assumes moderate leakage rates equal to mineral oil transformers.

b. Assumes moderate leakage rates equal to highest rate in equipment surveyed (i.e., oil-filled circuit breakers).

TVPPA study shows auxiliary drives for hydraulic aerial devices save fuel, $

PAYBACK PERIODS
(No refueling savings—years to repay cost of auxiliary drive)

	Auxiliary Drive Type							
	Electric		Gasoline		Propane		Diesel	
Type of truck	Aux. cost	Payback	Aux. cost	Payback	Aux. cost	Payback	Aux. cost	Payback
Gasoline fueled								
Service-city & rural	–	–	$2500	>15.00 yr	–	–	–	–
Line-city	$9000	10.52 yr	2500	6.63 yr	$3900	5.00 yr	$6800	7.67 yr
Line-rural	$9000	>15.00 yr	2500	>15.00 yr	3900	>15.00 yr	6800	>15.00 yr
Tree-trim, city	9800	6.15 yr	2500	5.31 yr	3900	>15.00 yr	6800	5.85 yr
Tree-trim, rural	9800	>15.00 yr	2500	2.70 yr	3900	>15.00 yr	6800	9.22 yr
Propane-fueled								
Service-city & rural	–	–	similar to paybacks for gasoline trucks above		2900	>15.00 yr	similar to paybacks for gasoline trucks above	
Line-city	9000	>15.00 yr			2900	>15.00 yr		
Line-rural	9000	>15.00 yr			2900	>15.00 yr		
Tree-trim, city	9800	>15.00 yr			2900	>15.00 yr		
Tree-trim, rural	9000	>15.00 yr			2900	>15.00 yr		
Diesel-fueled								
Service-city & rural	–	–	–	–	–	–	–	–
Line-city	9000	>15.00 yr	2500	>15.00 yr	–	–	6800	>15.00 yr
Line-rural	–	–	–	–	–	–	6800	>15.00 yr
Tree-trim, city	9800	>15.00 yr	2500	>15.00 yr	–	–	6800	>15.00 yr
Tree-trim, rural	9800	>15.00 yr	–	–	–	–	6800	>15.00 yr

Data in unshaded areas, indicates economic viability. Payback periods were calculated on a discounted life-cycle cost technique with fuel cost escalation. Discount rate was 10 percent. Fuel escalation was calculated on 3 percent more than the discount rate for 3 years, 5 percent more than the discount rate thereafter.

CHATTANOOGA, TN — Auxiliary drives for aerial devices — gas-, diesel-, propane-, or battery-powered — can save money and fuel for utilities, compared to using the vehicle's engine to drive a hydraulic pump through a Power Take Off (PTO). But, concludes a new study conducted for the Tennessee Valley Public Power Association (TVPPA), the extent of the savings is dependent on type of vehicle, extent of usage, and the locale where the vehicle is used.

The study, which was conducted for TVPPA by Lupton Engineering Associates, Inc., Chattanooga, focused on the different types of auxiliary drives available, their advantages and disadvantages and the types of usage for which each was best suited. Factors considered included the impact of specific truck fuel, truck usage (city or rural), and vehicle type (service, line or tree-trimming).

Conclusions

The study report listed the following results and conclusions:

- All types of auxiliary drives can save some fuel and reduce direct operating expenses when installed on line trucks or tree-trimming vehicles.
- Auxiliary drives offer the greatest payback when used on trucks fueled with gasoline and propane.
- Electric auxiliary drive's greatest advantages are quiet operation and elimination of exhaust fumes in the work area.
- Gasoline engine auxiliary drives' greatest advantage is their low first cost, which provides an excellent payback.
- Diesel engine auxiliary drives' greatest advantages are long engine life and very low fuel consumption.
- Electric auxiliary drives work better on aerial lifts with closed center hydraulic systems than on those with open center systems.
- Auxiliary drives *do not* offer significant fuel or operating cost savings when used on service type trucks.
- Auxiliary drives *are not* cost effective for bucket trucks that use less than six (6) gallons of fuel per day in non-road use.
- Auxiliary drives used on diesel-fueled trucks do not provide any substantial additional savings over those significant operating cost reductions obtained by diesel fuel use itself.

The rationale behind the study was that a bucket-truck operator does not need the power of a 200 hp or greater truck engine to operate a 10 hp hydraulic pump. Also, pump operation is intermittent, not constant, and therefore does not require constant motor idling.

Use of auxiliary power units to drive the hydraulic pump provides sufficient power, as needed, with much lower energy consumption than a truck engine. Moreover, less wear on the engine for pump operation contributes to longer trouble-free primary engine use to power the truck itself.

Auxiliary drives' benefits

Auxiliary drives offer four primary benefits to users. A major advantage is reduced fuel consumption. This means an immediate reduction in operating costs. A corollary to this is that with reduced consumption, more trucks could be kept in-service should there be a future fuel shortage. Engine wear also is reduced, often for periods up to 4 hours. This extends the time between oil changes, tune-ups, engine overhaul and rebuilding, and significantly increases the time of use before replacement. As a result, the study points out, truck reliability is improved and maintenance expenses are reduced.

Reduced engine use also decreases the time during the day required for refueling.

Since the auxiliary drive system is not designed to totally replace the PTO; but only to replace its use for powering the small hydraulic pump, a truck equipped with both has increased reliability in the field.

One major drawback to use of auxiliary drives is that during cold weather the cab of the truck will be cold. If the engine is used, the cab will be heated and work crews can periodically warm themselves.

Another disadvantage is that while the auxiliary drive is operating, the truck's battery system is called on to operate the radio, lights and supply power for the auxiliary drive control system. Since the battery is not being charged all day, as it would be if the truck were operated in the PTO mode, increased battery maintenance can be anticipated.

The auxiliary drive systems also require a capitol investment before any savings can occur. Payback can be several years.

The additional weight of the auxiliary drive equipment, especially with battery pack electric system, reduces available payload that the truck might otherwise carry.

And finally, addition of an auxiliary drive system means added maintenance.

Equipment

The auxiliary drive system can be either electrically-powered, from a separate battery system, or fuel-powered with gasoline, propane or diesel oil. If fuel powered, the report says, it's most economic to select an auxiliary drive that uses the same fuel as the truck itself.

New load management program allows customers to choose level of service

WASHINGTON, D.C. — Just like purchasing a car based on quality and price, a customer of Southern California Edison Company can now buy electricity according to the level of service he wants.

According to Geoffrey R. Bales of Edison, Demand Subscription Service (DSS) is the first major attempt by an electric utility to utilize a remotely-activated residential load management device that allows the customer to select his level of service. Bales recently presented the DSS program at the 9th Energy Technology Conference & Exposition.

After a customer decides to have DSS installed, a customer service representative is sent to evaluate the customer's use of power. An in-depth load check of all the appliances is done and the representative explains the impact of the different service levels that the customer can choose. A lock on the DSS prevents tampering with the load-limit switch. If the device is disturbed, an indicator light will alert the meter reader to the problem.

Eight signal towers located in metropolitan areas of Edison's service territory send out signals that activate the units. Although other approaches, such as powerline carriers, are being explored, Bales explained that signals are currently sent over VHF-FM radio waves. A computer console in Edison's general office building activates the DSS during a system capacity shortage.

When a customer exceeds the previously selected load-limit, signals from the towers will start an alert device. The device has three colored lights and an audio signal to inform the customer of the DSS status. A green light indicates that there is a system capacity shortage and that the unit has been put into operation. If the customer uses 75 percent or more of his predetermined service, a yellow warning light flashes. And if the customer exceeds his level, a red light flashes along with a continuous beeping noise for 1 minute. During that minute, the customer must reduce his load or service is temporarily cut off. Service can be restored by reducing load and pressing a button.

The load management device is easily installed between the electric meter and the user's panel. During the initial experimental stage in 1980 and 1981, the units were built to Edison's specifications using off-the-shelf components.

Since the level of service selected is only a constraint during system capacity shortages, Bales said the utility initially expected customers to respond favorably to the program.

More than 2,500 units were installed and Bales said reaction was very good. Customers were able to decide whether to use the air conditioner, electric water heater or any other mix of appliances. Edison also offered customers a reduction on their monthly bills if they participated in the experiment.

Initial testing indicated a peak load reduction of approximately 3 MW and gave Edison officials strong promise for the program. Bales said the DSS program proved to be cost effective when compared to the expenses involved with building and operating combustion peaking power plants.

An aggressive DSS plan is scheduled for the near future. By the end of 1984, Edison hopes to have 110,000 units installed throughout its service area. The company also estimates the peak load reduction will equal about 140 MW once the program is fully in place.

0906 25 1830645 1 W JPK
JOSEPH MCNALLY
CONGRESSIONAL INFORMATION
SERVICE INC
4520 EAST-WEST HWY-STE 800
WASHINGTON DC 20014

C8650-4
4/17/82

Volume 60, Number 6
June 1982

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Officials chide industry for lack of TMI action

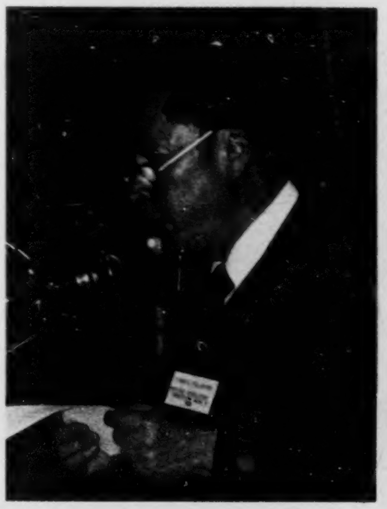
ST. CHARLES, IL — Calling the pace of cleanup activity at the TMI accident site "disturbingly slow," Nuclear Regulatory Commission chief Nunzio Palladino said he wants the nuclear industry to take action. Speaking at the same conference here, which was sponsored by McGraw-Hill Co.'s nuclear industry newsletters, White House science advisor John Marcum said he found it "unusual" that nuclear utilities have not yet provided the $190 million pledged to TMI cleanup by EEI.

Palladino said he is worried that GPU's insurance money, now being used for the cleanup, is going to run out. He called TMI an unstable situation well on its way to becoming a "serious" situation. He said the longer industry waits the longer the scar of TMI will remain. "I do not hear the voice of the nuclear industry," on TMI cleanup, added the NRC head.

White House advisor Marcum, who is assistant director for energy and natural resources in the Office of Science Technology and Policy, said that the federal government has taken the initiative in providing TMI cleanup funds via the $125 million promised for R&D aspects of the cleanup. The time has come for the utility industry to put up its share, said Marcum. The money is available, he claimed, noting that four times as much as the money pledged to cleanup has been sent to EPRI.

Both Marcum and Palladino called on the industry to improve post-TMI operations. Marcum noted that there are still major unsolved operating problems such as steam generator tube failures and pressure vessel embrittlement. He also said that the financial risk to nuclear utilities remained "intolerable" since a program of full insurance coverage for another TMI-type accident has not yet been obtained.

Palladino also felt that utilities should continue to upgrade efforts to absorb lessons learned from TMI. He was particularly concerned that utilities continue to strengthen their quality assurance programs.



NRC chairman Nunzio Palladino on the lack of outside help for the TMI cleanup problem: "If the industry doesn't see that it has an enormous stake in a satisfactory conclusion to that momentous accident, then perhaps there is less hope for expeditious removal of this scar from the back of the industry than I thought."

PUCs move to halt Pebble Springs, Limerick nukes

BARRINGTON, IL — The public utility commissions in Oregon and Pennsylvania, concluding that continued construction of nuclear projects in their states is not in the best interest of ratepayers, have stepped in to oppose building the plants.

While state agency intervention is different in the cases of Portland General Electric's proposed two-unit Pebble Springs plant and Pennsylvania Electric's Limerick plant, both manifest what appears to be a growing inclination on the part of commissions to take the initiative in deferring or cancelling nuclear projects.

Earlier this year Public Service Electric & Gas Company entered into a negotiated settlement with the NJ Public Advocate's Office and Board of Public Utilities with respect to Hope Creek-2. The company cancelled the plant on the basis that it would be allowed to recover substantial portions of its investment in the enterprise (see *EL&P*, March, 1982, page 3; and April, 1982, page 1).

In early May, the PA PUC, reading the sentiment of the state legislature, decided that it would not grant Philadelphia Electric's request to include some $500 million of construction work in progress (CWIP) in the rate base for the company's two Limerick nuclear plants. This action, in turn, led the agency to conclude that without such financial help, it would be impossible for PE to continue building the two nuclear units on its current schedule. Rather than risk another slippage, the PUC decided to do what it could to nudge Philadelphia Electric into suspending construction on unit 2 while concentrating its efforts and resources on unit 1.

Both Limerick units are nominally 1,055 megawatts, and as of December 31, 1981, unit 1 was about 70 percent complete and unit 2 about 30 percent complete. Target completion dates for the two plants are 1985 and 1987.

According to a PUC motion drafted by commission chairman Susan Shanaman, an analysis of Limerick construction in light of the CWIP request denial showed that completion of unit 2 by 1987 was "not financially feasible." While the majority of the commissioners agreed, they felt they did not have the legal authority to order outright that Philadelphia Electric cancel unit 2. The commission de-

Continued on page 16

Justice Dept. seeks to block Initiative 394

WASHINGTON, D.C. — The U.S. Department of Justice, at the urging of the Department of Energy, has filed suit challenging the constitutionality of Initiative 394 passed by Washington State voters late last year.

The referendum, passed on November 3, 1981, in effect requires the Washington Public Power Supply System to secure voter approval before it can sell any bonds to finance its on-going nuclear construction program. Currently, the supply system has three plants in construction, all of them well along in construction. It had been estimated that about $3.7 billion in additional financing would be necessary to complete WNP-1, WNP-2, and WNP-3. The initiative is to become effective July 1, 1982.

The announced deferral of WNP-1 is expected to reduce construction expenditures somewhat (see story, this issue).

The thrust of the Justice Department's complaint is that the initiative, if allowed to stand, essentially subverts not only the agreements that exist between the supply system and the Bonneville Power Administration (which is to market the power

Continued on page 6

NARUC group forms first diversification 'rules'

Dan Utroska
Associate Editor

MADISON, WI — In a second floor hotel conference room here, down the street from the grand state capitol building, five state regulators met late one evening in May to discuss the regulatory response to the growing electric utility attention to diversification. What they concluded at that meeting may well constitute the basis for the final rules governing electric company diversification for the next decade.

At the hand of each regulator was the draft report that earlier had been issued by their group — the Ad Hoc Committee on Utility Diversification of the National Association of Regulatory Utility Commissioners. The committee had issued the draft report in April without conclusions or recommendations as a prelude to holding public hearings on issues related to diversification.

Now that the first two days of hearings had been concluded, the five commissioners sat pondering the implications of what they had heard, trying to integrate it with what they already understood about the problems attendant to utility diversification. Theirs was a first effort to crystallize into public policy a set of workable guidelines that could be used by public service commissions across the nation in dealing with the principal issues.

Few active participants

Although the NARUC Ad Hoc Committee on Utility Diversification officially consists of 10 regulators from various states, only seven made it to Madison to participate in public policy discussions. And by the time the committee reconvened at 8 p.m. after adjourning for dinner on the first day of hearings, only five remained. Of these, Stanley York of the Wisconsin Public Service Commission, V. Louise McCarren of the Vermont Public Service Board, and Richard E. Schuler of the New York Public Service Commission, formed the active intellectual core of the group, with the other commissioners present mostly listening and agreeing with final determinations.

Policy issues solidified

At a preliminary meeting of the ad hoc committee held just before the dinner recess, each of five commissioners was given one of the five critical policy issues identified by the committee and asked by the chairman to return later that evening prepared to recommend the adoption of specific proposals. Given the stated need to balance the phrasing of these platform statements so they would be general enough to apply to all state regulatory jurisdictions, on the one hand, yet be specific enough to have teeth at the regional level, on the other hand, the task of formulating such proposals over the competing attention of a Ceasar salad, a couple of pork chops, and the distant clinking of Martini glasses must have been a challenge indeed.

Continued on page 7

Foreign Power Briefs

- **A 1.2 million-kW hydroelectric station** will be constructed by Soviet workers in Angola on the Kwanzi River, according to the Yugoslav news agency Tanjug. Angola's foreign trade and planning minister said that he signed documents calling for major Soviet assistance in construction, industry, agriculture and transportation.

- **Spain will continue work** on the Lemoniz nuclear plant in the northern Basque region. Work on the facility was delayed for more than a year because of terrorist threats and attacks. An agreement was recently signed by Iberduero, a Spanish utility, the Basque government, and the central government in Madrid. Iberduero will still have financial control and ownership of the plant, but operating and management control of the plant will be in the hands of the Basque regional government. The $1.5 billion 930,000-kW station is 96 percent complete.

- **A New South Wales, Australia electric utility** has arranged a 15-year multicurrency loan equivalent to $1.25 billion. Eraring Power Company will use the funds to build a power generating complex for the Electricity Commission of New South Wales. The facility will consist of four 660,000-kW generating units. Officials estimate the plant should be complete in 1984. Funds for the loan were provided by 36 international banks.

- **New nuclear technology exchange agreements** were signed by General Electric and Kraftwerk Union. Officials of both companies said the agreement will broaden and expand the information exchange pacts between the two electrical equipment suppliers. They will exchange ideas and information on boiling water reactors, fuel for nuclear power plants and maintenance services for BWR nuclear power plants.

- **World trade in coal will double** in this decade, according to Dr. Irwin M. Stelzer, president of National Economic Research Associates, Inc.. In a recent report, he noted that U.S. exports will double while those of Australia and South Africa will triple by 1990.

- **France** is expected to have an 80 percent nuclear dependency by the end of this decade. The Atomic Industrial Forum reports in its annual survey of commercial nuclear energy use that France has become the first country to make nuclear a primary source of power. In the past seven years France's nuclear growth has risen from 10 percent to 38 percent last year. The AIF also says that the world's total nuclear capacity increased more than 20 percent last year.

- **West Germany's government** has given the OK to a financial plan that would save the fast breeder reactor at Kalkar. After negotiations between West German power utilities and Research Minister Andreas von Bulow, the government decided to let the project be completed. Interim financing for the reactor will come from the Ministry of Finance. The utilities will contribute additional funds to the project if the West German Bundestag(Parliament) approves Kalkar's operating license before September.

- **Engineers at the Oil Institute in Ufa, the capital of the Soviet republic of Bashkiria,** designed a trolleybus airship system. With a propellor at each end, the helium-filled airship flies above a contact wire through which electricity runs the ship's motors. Officials say the airship will be used for carrying people and heavy freight over rough terrain for use in the energy industries. A trolley line for the supply airships can be built for 2 percent of the cost of constructing a road in the remote parts of Siberia.

- **Soviet engineers** are surveying a site for a possible 20,000 MW hydroelectric power station on the Lower Tunguska River in central Siberia. If a dam is built, a reservoir 1,000 km long would be made.

- **Egypt and Canada** have signed a joint statement on nuclear cooperation. The governments of those two countries will explore possibilities of entering into nuclear cooperation and in negotiating a formal agreement.

- **The People's Republic of China** begins a nuclear power program with a 300 MW PWR in the Shanghai area. Sources say that only the reactor may be purchased from abroad.

- **Using their own technology, Argentina** built a small-scale reprocessing plant to allow recycling in thermal reactors, research into breeder technology and entrance into the export market for reprocessed fuel.

- **Japan's Atomic Energy Research Institute** intends to build an experimental multi-purpose High Temperature Gas-Cooled Reactor (HTGR) in 1986. Criticality is expected to be reached sometime in 1991. Using slightly enriched uranium as fuel and helium as coolant, the reactor will have an output of 50 MWt.

- **Brazil's Minister of Mines and Energy, Cesar Cals** has announced his government's plans to build 8, rather than 14, nuclear power stations by the end of the century. Cals cited a sharp reduction in demand for electricity as the main reason for the cutback. The low growth in demand has also caused work on ten hydroelectric and thermal power stations to be postponed or slowed.

- **Westinghouse received an order for more than $33 million from the Egyptian Electric Authority** for a 105,000-kW combustion turbine power plant. In cooperation with Italian and Egyptian firms, Westinghouse will build the facility at El Siouf, near Alexandria. To be fueled by natural gas with petroleum as backup, the plant will serve the baseload needs of the Alexandria area.

CP National buys Warner-Whitney

SAN FRANCISCO — CP National corporation has acquired the Warner-Whitney Group, Inc., of Houston.

Ben W. Agee, chairman and chief executive officer of CP National, announced the acquisition and said, "Due to the forthcoming deregulation of the Bell System Companies in 1983 and the fostering of competition of the telecommunications industry, CP National is committed to rapid expansion in both areas."

The company also announced that it will not go after ownership in Trident Energy Systems, Inc. as previously announced. CP National had intentions of acquiring 30 percent of Trident, a Davis, California solar energy company.

CP National serves over 135,000 retail electric and 336,000 gas and telephone customers in California.

In This Issue

Editorial 4

Improved utility financial performance in 1981 can be seen in EL&P's 17th annual financial analysis of the Top 100 investor-owned utility companies . 19

The Japanese are defining the next evolution in nuclear plant design by U.S. reactor suppliers, since there's no sign of U.S. demand. **G** 27

A pulverizer replacement program at Dayton Power & Light has resulted in substantial improvements in power plant availability. **G** 34

A supplier of self-cleaning flue-gas oxygen analyzers tells how maintenance costs were cut at Baltimore Gas & Electric. **G** 39

Westinghouse supplies the first commercial distribution transformer with an amorphous metal core to Georgia Power Co. **T/D** 41

A new SCADA system at Boston Edison required beefed-up telephone communications. **T/D** 42

An architectural interior planner explains how to humanize energy control centers. **T/D** 47

New Products 78

New Literature 80

Advertisers' Literature 87

Personnel 90

Regulatory Review 91

Management Methods 94

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

N.Y. utilities spend $83 million on new research, development

NEW YORK — In an effort to improve production, distribution and conservation of electric energy, New York state investor-owned electric utilities will spend $83 million for research this year.

Details of the plan were released by the Empire State Electric Energy Research Corporation (ESEERCO) as part of the long-range planning document of the New York Power Pool.

ESEERCO's report outlines R&D projects to assist the seven utility members in meeting their goal of providing more reliable, economic and environmentally compatible electric service to customers.

Four projects comprise the major portion of the group's program. Capable of producing 4,800 kilowatts, the first large-scale demonstration of a fuel cell power plant on a U.S. utility system is scheduled to be completed in mid-1982. The plant is located next to Consolidated Edison's East River Generating Station in New York. Nearly $1.3 million has been allocated for the project.

A test program will be used in evaluating the effects of using refuse-derived fuel on Rochester Gas & Electric Corporation's Russell Plant and the environment. Such fuel is now partially replacing coal at the plant.

Two other projects are also underway to improve the use of coal in an environmentally acceptable manner. Researchers are seeking to develop better methods of cleaning coal before it is burned at a test facility in Homer, PA. Nearly $225,000 will be used this year for R&D at the plant, which is owned by New York State Electric & Gas Corporation and Philadelphia Electric Company.

Also, a regenerative flue-gas desulferization project at Niagara Mohawk Power Corporation's Huntley Station is providing researchers with information on ways to reduce wastes created by present desulferization methods. Cost of the Huntley Station project for this year is $3.5 million.

Members of ESEERCO are: Central Hudson Gas & Electic Co.; Consolidated Edison; Long Island Lighting Co.; Niagara Mohawk Power; New York State Electric & Gas Corp.; Orange and Rockland Utilities; and Rochester Gas & Electric Corp..

NARUC supports limited ownership of cogeneration

WASHINGTON, D.C. — The National Association of Regulatory Utility Commissioners has gone on record in support of the current regulation that limits to 50 percent the ownership of cogeneration and small power facilities by utilities.

In testimony before the Senate Energy and Natural Resources Committee's Energy Regulation Subcommittee, Susan M. Shanaman, Chairman of the Pennsylvania Public Utility Commission, said that repeal of the 50 percent limitation rule would encourage electric utilities to invest capital in unregulated subsidiaries at the expense of utility ratepayers.

Continued on page 24

The 17th Annual Top 100 Electric Utilities Report

Large power companies gained back some lost financial strength in '81

Robert A. Lincicome, Editor-in-Chief

The nation's 100 largest electric utilities posted sizeable revenue, income and per-share earnings gains in 1981, generally overcoming the negative effects of continued inflation, high interest rates and reduced growth in kilowatthour sales. Their performance in 1981 enabled many among the Top 100 to regain some of the financial strength lost over the past several years.

Overall, the gains posted by the Top 100 Electric Utilities were considerably stronger than over the past four years. As might be expected, new record totals for revenues, net income and kilowatthour sales were achieved. Even kWh sales, which gained less than 2 percent in 1981, was a substantially better performer than at any time since 1976.

The achievements of the Top 100 are especially noteworthy in light of continued near-record interest rates, mounting construction costs and sagging demand growth. A year ago we commented that the Top 100 Electric Utilities were "battered by double-digit inflation, undercut by the effects of the recession on industrial load, bled by record high interest rates, frustrated by ever-lengthening construction schedules and victimized by inadequate and unrealistic rate relief." That summation was equally pertinent in 1981, too, except that there was improvement in the rate relief granted during the year. Moreover, skyrocketing fuel costs moderated part way through the year and the effects of subsidiary activities (in non-utility, non-regulated areas) had a positive effect.

The year 1981 cannot be said to have been an easy year, but it proved to be somewhat less-difficult than either 1980 or 1979.

Summary achievements

During 1981, the Top 100 Electric Utilities generated unprecedented revenues of $112.7 billion. This represents an increase of 20.3 percent and reflects the importance of rate relief granted by state public utility commissions. In 1981, kilowatthour sales increased less than 2 percent in the face of recessionary pressures, both direct and indirect, on all classes of customers. Utilities received larger amounts of rate relief in 1980 and early 1981 that fattened revenues despite slow sales growth. Increased collections under fuel adjustment clauses early in the year and improved results from more non-utility, non-regulated activities also contributed to the higher revenues.

Net income for the Top 100 increased even more, reflecting the strong efforts of utility managements to operate more efficiently and economically. Net Income in 1981 rose 22.2 percent, to $10.2 billion. In 1980, Net Income of the Top 100 was $8.35 billion; in 1979, $7.43 billion.

The rate of increase, 22.2 percent, is the highest in a number of years.

One problem with net income growth for the Top 100 Electric Utilities was the increasing role played by Allowance for Funds Used During Construction (AFUDC). AFUDC produces a net addition to income, but only as a paper entry. In large amounts, AFUDC degrades the quality of income and per-share earnings. This is a growing concern, even though the income performance of the Top 100 was markedly better than in 1980.

While the growth of Net Income was high, the effect was mitigated because utilities in 1981 again sold large blocks of common stock to raise needed capital. Despite the increased shares outstanding, per-share earnings improved substantially, for the first time in more than 5 years.

Average per-share earnings were $2.82, up 30 cents per-share from 1980. The increase per average share in 1981 was also three times the cumulative per-share increase from 1977 through 1980. Earlier average per-share earnings were: 1977 — $2.42; 1978 — $2.50; 1979 — $2.51 and 1980 — $2.52.

Kilowatthour sales

Kilowatthour sales moved up slightly in 1981, to 1.84 trillion kWh. This is an increase of 1.7 percent, compared to sales for 1980, which were 1.81 trillion kWh. Going back to 1974, the first full year of post-embargo effects, kWh sales totalled 1.45 trillion. Thus, in the 8 years since the OPEC nations changed the world oil picture, kWh sales by the Top 100 Electric Utilities have increased by 390 billion kWh, 26.9 percent or an average 3.36 percent per year. This is less than half the historic annual kWh sales growth rate prior to 1974.

The low kWh sales growth reflected the negative impact of the recessionary business cycle on commercial and industrial customers, as well as the effect of ever-higher rates on residential usage.

Both residential and commercial sales began the year well, with commercial sales remaining relatively

EARNINGS GROWTH STATISTICS

Company Name	Rank	% Change From 1980	1981 Earnings Per Share
San Diego Gas & Electric	1	131.68	$2.34
Nevada Power	2	118.99	$3.46
Savannah Electric & Power	3	95.90	$2.39
Puget Sound Power & Light	4	78.12	$2.85
Florida Power	5	68.67	$2.80
Central Vermont Public Service	6	63.32	$3.74
Tucson Electric Power	7	60.34	$3.80
Ohio Edison	8	51.32	$2.30
Missouri Public Service	9	50.89	$2.56
Kentucky Utilities	10	43.71	$2.17
Rochester Gas & Electric	11	43.63	$2.93
Washington Water Power	12	41.20	$3.29
Southern California Edison	13	40.86	$4.93
Consolidated Edison	14	37.90	$6.44
Dayton Power & Light	15	35.68	$2.51
Montana-Dakota Utilities	16	31.96	$2.89
Iowa-Illinois Gas & Electric	17	28.26	$3.46
Toledo Edison	18	27.73	$3.27
Public Service of New Mexico	19	25.89	$4.23
Niagara Mohawk Power	20	25.67	$2.36
Portland General Electric	21	25.12	$2.54
Eastern Utilities Associates	22	24.54	$2.03
Wisconsin Electric Power	23	24.36	$4.39
Montana Power	24	23.55	$4.04
Middle South Utilities	25	21.39	$2.44
South Carolina Electric & Gas	26	20.79	$2.44
Northern States Power	27	20.43	$3.89
Pennsylvania Power & Light	28	20.08	$3.17
Central Illinois Light	29	20.00	$2.40
Minnesota Power & Light	30	19.61	$3.06
United Illuminating	31	19.10	$4.24
Arizona Public Service	32	18.55	$3.26
Oklahoma Gas & Electric	33	18.50	$2.05
Interstate Power	34	18.29	$2.07
Allegheny Power Systems	35	16.99	$3.03
New England Electric System	36	15.71	$4.05
Atlantic City Electric	37	15.66	$3.03
Wisconsin Power & Light	38	15.53	$3.05
Detroit Edison	39	15.43	$2.02
Duquesne Light	40	13.19	$2.06
Philadelphia Electric	41	12.50	$2.25
Central Illinois Public Service	42	12.34	$1.73
Carolina Power & Light	43	12.09	$3.06
Cleveland Electric Illuminating	44	11.50	$2.52
Pacific Power & Light	45	11.46	$2.82
Delmarva Power & Light	46	11.26	$1.78
Central Telephone & Utilities	47	10.83	$3.89
Kansas City Power & Light	48	10.78	$4.83
Boston Edison	49	10.67	$4.15
Texas Utilities	50	10.39	$3.51
Central Hudson Gas & Electric	51	10.06	$3.72
Gulf States Utilities	52	9.27	$2.24
New York State Electric & Gas	53	9.26	$2.95
El Paso Electric	54	8.78	$3.23
Central Maine Power	55	8.38	$1.81
Florida Power & Light	56	7.87	$4.25
Public Service of Indiana	57	6.54	$3.42
Orange & Rockland Utilities	58	6.33	$2.35
Wisconsin Public Service	59	6.01	$3.00
Hawaiian Electric	60	3.70	$3.92
Central & South West	61	3.67	$2.54
Duke Power	62	3.57	$3.19
Iowa Resources	63	3.51	$3.54
Commonwealth Edison	64	3.03	$3.06
Public Service of Colorado	65	2.60	$1.97
Kansas Power & Light	66	2.48	$3.30
Cincinnati Gas & Electric	67	2.22	$2.30
Potomac Electric Power	68	1.90	$2.14
Baltimore Gas & Electric	69	1.65	$3.70
Consumers Power	70	1.30	$3.12
Long Island Lighting	71	0.79	$2.55
Idaho Power	72	0.33	$3.05
Central Louisiana Electric	73	0.00	$2.46
Houston Lighting & Power	74	0.00	$3.14
American Electric Power	75	−0.84	$2.37
Illinois Power	76	−1.06	$2.84
Northeast Utilities	77	−1.53	$1.29
Southwestern Public Service	78	−2.17	$1.80
Iowa Public Service	79	−2.53	$2.70
Utah Power & Light	80	−2.55	$2.29
General Public Utilities	81	−2.94	$0.33
Southern Indiana & Gas Electric	82	−3.21	$3.32
Teco Energy	83	−3.85	$3.00
Kansas Gas & Electric	84	−4.04	$2.85
Public Service of New Hampshire	85	−4.33	$2.65
Iowa Electric Light & Power	86	−4.83	$1.97
Sierra Pacific Power	87	−5.13	$1.48
Pacific Gas & Electric	88	−5.28	$3.41
Northern Indiana Public Service	89	−6.80	$1.37
Louisville Gas & Electric	90	−6.87	$2.71
Virginia Electric & Power	91	−8.29	$1.77
Union Electric	92	−9.52	$1.90
Empire District Electric	93	−15.82	$1.33
Public Service Electric & Gas	94	−15.97	$2.63
Southern Company	95	−18.83	$1.81
Indianapolis Power & Light	96	−23.64	$2.81
Madison Gas & Electric	97	−24.89	$1.66
Texas-New Mexico Power	98	−25.31	$2.39
Commonwealth Energy System	99	−26.25	$2.22
Otter Tail Power	100	−32.02	$1.72

SALES DATA

	1981 Total Sales (KWH)			1981 Sales (KWH) By Type of Customer (% of Sales)				Average Annual Residential Use		Ratio of Long Term Debt to Net Plant	
Company	Rank	% Increase	Average Annual Growth 1976 – 1981	Resid.	Comm.	Ind'l	Other	1981	1980	1981	1980
Allegheny Power Systems	1	26.58	3.92	19.8	10.7	35.9	33.6	8,788	8,718	46.0	47.1
Central Hudson Gas & Electric	2	16.25	4.91	21.1	18.5	21.8	38.6	6,268	6,379	71.6	68.0
Sierra Pacific Power	3	13.12	5.34	28.6	36.0	19.6	15.9	7,302	7,539	43.0	4.4
Arizona Public Service	4	12.72	4.73	28.4	29.3	19.5	22.9	10,247	9,995	45.6	47.1
Central Vermont Public Service	5	10.44	2.77	37.2	8.5	34.0	20.3	7,866	7,704	59.9	54.4
Portland General Electric	6	10.33	3.11	34.9	26.1	24.1	14.8	12,141	12,918	83.2	87.3
Ohio Edison	7	10.13	1.13	27.4	19.9	37.9	14.8	7,760	7,870	45.5	46.4
Nevada Power	8	10.01	4.56	43.5	2.2	48.0	6.1	14,527	14,248	48.9	42.1
Tucson Electric Power	9	10.01	10.14	18.8	16.7	29.2	36.2	7,684	7,614	45.7	48.1
Washington Water Power	10	9.97	0.31	23.8	18.8	25.1	32.3	14,697	15,130	52.4	55.5
Interstate Power	11	9.63	3.72	20.7	15.6	46.9	16.9	6,790	7,114	52.1	52.0
Public Service of New Mexico	12	6.84	10.05	19.2	25.7	14.9	40.2	5,697	5,782	44.7	42.8
Pacific Gas & Electric	13	5.79	0.61	31.7	30.4	26.6	11.3	5,569	5,606	44.4	45.1
Montana-Dakota Utilities	14	5.60	5.25	42.2	27.1	26.7	4.0	7,463	7,413	45.3	49.7
Texas-New Mexico Power	15	5.27	6.10	27.6	19.4	50.7	2.3	10,244	10,842	40.3	44.6
Central Maine Power	16	4.81	3.19	30.8	23.2	35.6	4.0	6,777	6,862	51.1	44.6
Pacific Power & Light	17	4.68	2.99	28.1	21.0	27.9	23.0	12,091	12,608	54.3	52.3
Puget Sound Power & Light	18	4.38	2.43	47.2	22.7	16.0	14.2	14,626	15,489	48.2	47.1
Southern California Edison	19	4.23	2.32	26.7	29.5	30.9	12.8	5,879	5,939	47.5	47.1
Houston Lighting & Power	20	3.79	6.83	22.7	17.4	53.7	6.1	13,590	14,219	40.2	40.4
San Diego Gas & Electric	21	3.66	3.21	35.9	34.1	24.2	5.8	5,471	5,666	40.5	46.0
Idaho Power	22	3.50	1.14	25.4	28.4	27.4	18.9	14,054	14,446	47.0	48.8
Florida Power & Light	23	3.48	5.60	49.6	33.7	7.5	9.3	11,216	11,473	41.9	40.8
Florida Power	24	3.45	5.39	39.8	19.2	16.9	24.1	10,758	10,643	46.6	47.8
Duquesne Light	25	2.50	1.25	21.0	29.8	48.3	0.9	5,698	5,770	49.3	47.6
New York State Electric & Gas	26	2.41	1.08	40.2	22.8	25.8	11.1	7,393	7,289	42.8	40.7
Duke Power	27	2.36	2.93	25.9	18.2	38.6	17.3	12,392	12,560	42.3	43.8
Teco Energy	28	2.35	4.04	34.5	21.2	38.2	6.1	12,708	12,384	39.9	41.5
Philadelphia Electric	29	2.34	1.03	28.4	11.0	52.8	7.9	6,898	7,058	48.1	45.8
Baltimore Gas & Electric	30	2.07	3.35	34.2	17.1	48.8	0.0	7,848	7,958	47.3	48.8
Pennsylvania Power & Light	31	2.05	2.10	35.2	25.7	34.7	4.4	9,157	9,205	48.0	46.4
Central & South West	32	1.93	6.09	24.0	18.8	30.2	27.0	9,894	10,332	41.0	38.7
Southern Company	33	1.90	3.01	25.7	18.8	37.6	17.8	10,645	11,027	55.1	54.2
Public Service of Colorado	34	1.84	5.56	26.9	36.3	26.9	9.8	5,734	5,937	41.4	43.7
Cincinnati Gas & Electric	35	1.84	3.36	34.6	23.0	31.6	10.8	9,592	9,994	48.2	48.2
Wisconsin Public Service	36	1.70	3.06	27.1	22.8	31.2	19.1	7,172	7,187	41.6	47.2
Northern States Power	37	1.68	2.81	26.9	13.2	39.6	20.3	7,136	7,256	38.0	37.2
Virginia Electric & Power	38	1.68	3.01	33.6	24.6	16.1	25.7	10,948	11,056	62.6	51.7
Savannah Electric & Power	39	1.49	2.01	36.0	26.3	34.2	3.4	10,340	10,433	54.2	47.4
American Electric Power	40	1.35	4.01	18.7	12.1	32.0	36.1	10,032	10,120	54.8	54.3
Boston Edison	41	1.31	2.12	21.6	39.9	15.7	22.8	5,190	5,378	45.0	41.0
Potomac Electric Power	42	1.28	3.09	24.2	41.4	25.2	9.2	8,790	8,971	44.6	47.8
Oklahoma Gas & Electric	43	1.21	6.21	25.2	16.3	22.1	36.4	10,515	11,520	43.6	45.9
Dayton Power & Light	44	1.15	2.06	35.1	19.6	30.1	15.2	9,591	10,042	83.1	84.9
Hawaiian Electric	45	1.10	2.55	28.6	22.0	48.4	1.0	7,173	7,335	40.7	42.0
Niagara Mohawk Power	46	0.93	0.49	25.7	28.6	35.4	10.3	6,914	6,843	44.8	47.6
Montana Power	47	0.86	2.93	19.8	18.2	27.9	34.1	7,977	8,055	50.3	43.0
Atlantic City Electric	48	0.74	4.16	43.7	32.6	22.5	1.2	7,923	8,003	44.7	44.9
Carolina Power & Light	49	0.88	3.37	25.4	16.6	32.7	25.3	12,087	12,558	45.4	43.1
Consumers Power	50	0.85	0.48	30.9	24.2	40.5	4.4	6,642	6,812	40.3	46.1
Gulf States Utilities	51	0.55	6.36	20.6	15.0	54.2	10.2	12,786	13,173	47.5	46.5
General Public Utilities	52	0.55	2.24	33.4	24.8	36.0	5.7	7,560	7,726	53.3	54.9
Southwestern Public Service	53	0.47	4.34	14.4	16.1	43.5	26.0	7,148	7,601	46.1	47.9
Northern Indiana Public Service	54	0.42	0.59	16.7	3.6	71.7	8.0	6,720	7,026	49.6	48.2
Iowa-Illinois Gas & Electric	55	0.40	3.54	22.8	27.2	44.9	5.1	5,998	6,488	39.9	38.7
Wisconsin Electric Power	56	0.36	1.96	29.6	24.2	34.5	11.7	7,149	7,314	45.5	46.9
Minnesota Power & Light	57	0.35	10.38	8.7	7.6	66.8	17.8	7,878	7,692	45.0	47.0
Northeast Utilities	58	−0.05	1.42	36.2	29.2	25.7	8.8	7,548	7,664	48.3	51.5
Texas Utilities	59	−0.22	8.39	32.0	26.4	30.8	10.8	11,862	13,126	40.9	41.7
Indianapolis Power & Light	60	−0.39	2.29	31.4	20.3	47.1	1.2	9,228	8,821	42.4	38.0
Southern Carolina Electric & Gas	61	−0.40	2.89	31.5	23.7	35.4	9.4	12,183	12,580	44.2	46.1
Iowa Electric Light & Power	62	−0.51	3.14	34.6	25.6	30.7	9.1	7,894	8,275	44.6	46.7
New England Electric System	63	−0.51	0.58	35.0	29.5	24.8	10.7	6,025	6,241	43.8	45.4
Public Service of Indiana	64	−0.57	4.34	25.9	18.7	31.9	23.5	10,329	10,812	39.8	38.4
Detroit Edison	65	−0.65	−0.62	29.8	18.6	45.5	6.2	6,243	6,408	47.1	48.8
Otter Tail Power	66	−0.78	5.04	29.8	15.6	35.1	19.5	9,190	9,235	39.9	42.1
El Paso Electric	67	−0.78	2.20	26.1	28.0	19.0	26.9	5,849	6,066	31.3	32.0
Public Service Electric & Gas	68	−0.78	1.58	26.0	36.5	36.0	1.4	5,261	5,443	44.3	44.8
Delmarva Power & Light	69	−0.87	2.40	27.0	22.4	33.2	17.4	7,967	8,337	48.9	48.1
Consolidated Edison	70	−1.23	−0.95	25.5	5.2	57.8	11.5	3,231	3,340	42.8	46.3
Long Island Lighting	71	−1.31	2.16	41.7	0.0	48.5	9.8	6,815	6,956	49.2	47.5
Eastern Utilities Associates	72	−1.50	1.45	26.3	24.7	19.7	29.3	5,449	5,626	54.2	51.7
Kentucky Utilities	73	−1.56	−0.07	29.9	17.8	17.8	34.4	10,334	10,692	48.2	47.3
Commonwealth Edison	74	−1.59	1.33	27.9	30.9	30.6	10.6	6,291	6,625	47.7	47.8
Rochester Gas & Electric	75	−1.79	2.72	26.2	21.7	24.7	27.4	6,754	6,744	46.6	46.0
Illinois Power	76	−1.89	3.99	26.3	17.2	46.1	10.3	8,011	8,541	38.1	44.2
Union Electric	77	−2.08	3.22	31.9	28.9	32.0	7.1	8,955	9,848	47.3	46.2
Utah Power & Light	78	−2.35	4.95	20.6	15.7	39.4	24.2	7,821	7,693	46.8	46.0
Louisville Gas & Electric	79	−2.44	2.36	31.3	24.2	34.6	10.0	8,981	9,589	40.5	41.5
Public Service of New Hampshire	80	−2.50	3.57	29.5	10.2	30.1	30.2	6,849	7,178	30.1	38.1
Central Louisiana Electric	81	−2.62	5.55	37.3	15.6	40.5	6.6	11,288	11,404	49.9	56.9
Southern Indiana Gas & Electric	82	−3.07	5.39	21.5	16.2	32.2	30.1	10,081	10,869	48.5	37.6
Toledo Edison	83	−3.20	0.46	26.8	18.1	43.1	12.0	7,966	8,232	45.6	46.9
Kansas City Power & Light	84	−3.20	3.11	28.2	39.1	28.0	4.7	7,700	8,923	45.6	43.2
Orange & Rockland	85	−3.31	0.40	31.6	21.4	29.0	18.0	5,926	6,094	41.3	46.0
United Illuminating	86	−3.55	0.96	35.4	34.1	28.9	1.5	6,312	6,546	41.3	46.2
Cleveland Electric Illuminating	87	−3.59	0.10	25.0	23.9	47.3	3.8	6,807	6,886	44.4	45.2
Missouri Public Service	88	−3.71	2.01	38.4	25.2	18.9	17.5	7,857	8,924	51.9	49.7
Iowa Public Service	89	−3.80	5.21	33.4	23.9	31.7	11.0	6,918	7,438	50.8	47.7
Middle South Utilities	90	−3.84	8.86	29.2	17.7	44.7	8.4	11,347	11,969	60.8	51.2
Kansas Power & Light	91	−4.12	3.63	25.2	28.7	22.8	23.3	7,545	8,635	38.2	42.3
Iowa Resources	92	−4.16	3.18	38.8	24.8	33.8	2.5	7,988	8,783	39.9	42.0
Commonwealth Energy System	93	−4.27	−1.97	22.3	17.2	12.9	47.7	5,491	5,604	43.6	44.2
Central Illinois Public Service	94	−4.36	2.58	25.5	10.5	39.2	24.9	8,090	8,789	41.0	43.5
Wisconsin Power & Light	95	−4.36	5.47	29.3	16.1	28.6	25.9	7,806	8,002	45.2	42.1
Central Illinois Light	96	−4.71	3.43	29.5	30.2	38.2	2.1	8,434	9,135	36.0	38.6
Kansas Gas & Electric	97	−4.73	6.43	26.2	19.7	38.3	15.8	9,433	10,708	49.7	42.4
Central Telephone & Utilities	98	−7.20	4.38	25.6	25.1	21.8	27.5	6,461	6,968	45.3	48.7
Empire District Electric	99	−8.27	3.37	31.5	20.0	29.9	18.5	8,543	9,500	46.9	48.4
Madison Gas & Electric	100	−12.71	7.33	26.5	43.8	6.0	23.7	6,073	6,120	38.1	40.2

strong throughout the year except for one month. Residential sales weakened early in the year, recovered in the late Spring, slipped into a decline in the Fall and only recovered marginally at year-end.

Industrial sales lost ground early in the year, recovered in the late Spring and Summer, then went into a decline again through the end of the year.

Average residential customer use of electricity declined in 1981, for only the third time since *EL&P* launched its annual Top 100 Electric Utilities report program in 1966. The decline, 303 kWh, or 3.5 percent, is the biggest decline recorded. In total, 1981 average residential use was 8463 kWh, less than that posted back in 1977.

TABLE I
THE TOP 10 IN KWH SALES

Rank '81	Rank '80	Company	KWH Sales (millions)	'81% Change
1	1	American Electric Power	113,011	1.35
2	2	Southern Company	94,217	1.90
3	4	Southern California Edison	62,451	4.23
4	6	Pacific Gas & Electric	61,669	5.79
5	3	Commonwealth Edison	61,229	−1.59
6	5	Texas Utilities	58,372	−0.22
7	8	Houston Lighting & Power	56,880	3.79
8	9	Duke Power	53,548	2.36
9	7	Middle South Utilities	53,035	−3.84
10	10	Central & South West	47,850	1.93

Companies posting the highest average residential kWh use were, generally, located in the Pacific Northwest, where electric energy historically has been cheap, and in the Southeast. Leaders in 1981 were: 1. Washington Water Power, 14,697 kWh (-2.9 percent); 2. Puget Sound Power & Light, 14,266 kWh (-7.9 percent); 3. Nevada Power, 14,527 (2.0 percent); 4. Idaho Power, 14,054 kWh (-2.7 percent); and 5. Houston Lighting & Power, 13,590 kWh (-4.4 percent.

Overall, 57 companies reported kWh sales gains for 1981. This reflects a 23 percent decline for 1980 and down 30 percent from 1979. Aside from a half-dozen individual performances, 1981 gains tended to be smaller also. Forty-three utilities recorded negative growth in 1981, which ties 1981 with 1975 as the second worst sales-growth year in the past 17.

Table I reflects the relative standings of the ten companies reporting the largest kWh sales in the industry.

Revenues up

Total revenues reported by the Top 100 Electric Utilities in 1981 were $112.7 billion, compared to $93.7 billion in 1980. This represents a 20.8 percent gain, largest in recent years, and largely reflects the effect of rate increases granted by regulatory commissions in 1980 and early in 1981. The increase also reflects the positive results of subsidiary non-utility, non-regulated operations.

There were fewer large revenue gainers in 1981 than in 1980: 26 with increases above 20.0 percent and 54 between 10.0 and 19.9 percent in 1981, versus 47 above 20 percent and 44 between 10.0 and 19.9 percent a year earlier. However, the 1981 gains tended to be larger overall than a year previous.

The largest revenue gain was 54.7 percent, posted by Hawaiian Electric, followed by Allegheny Power System's 38.6 percent increase, and Central Hudson ahead 35.6 percent.

For several years we have listed the members of the Billion Dollar Club — utilities that received revenues of at least a billion dollars. The list now has reached 40 utilities and has become too long to publish. The list of companies recording $2 billion in revenues is shown as Table II.

Net income

Total net income of the Top 100 Electric Utilities rose 22.16 percent, to a record $10.2 billion. A year earlier, net income of $8.35 billion was reported by the Top 100. This is the largest increase in net income to be recorded in many years and reflects the rate relief granted by Commissions and utility managements' concerted efforts to control expenses.

TABLE II
LARGEST ELECTRIC UTILITY REVENUE PRODUCERS
(more than $2-million in revenues)

Rank '81	Rank '80	Company	Revenues (billions)	'81% Change
1	1	Pacific Gas & Electric	$6.195	17.8
2	2	Consolidated Edison	$4.866	23.3
3	3	Southern Company	$4.256	13.1
4	4	American Electric Power	$4.193	11.8
5	5	Southern California Edison	$4.055	10.7
6	6	Common-wealth Edison	$3.737	12.4
7	7	Public Service Electric & Gas	$3.472	16.0
8	8	Florida Power & Light	$3.089	31.6
9	9	Middle South Utilities	$2.772	18.3
10	12	Houston Lighting & Power	$2.769	30.4
11	11	Texas Utilities	$2.738	25.9
12	10	Consumers Power	$2.734	18.7
13	13	Philadelphia Electric	$2.433	14.6
14	29	Union Electric	$2.162	2.6
15	17	Niagara Mohawk Power	$2.151	21.0
16	32	General Public Utilities	$2.065	12.8
17	18	Central & South West	$2.055	18.7
18	16	Detroit Edison	$2.054	13.3

Twenty-two additional companies posted revenues between $1-billion and $2-billion.

As mentioned earlier, the effect of Allowances for Funds Used During Construction is a concern to utility managements, security analysts and investors in that it leads to an overstatement of *real* income. AFUDC is a paper transaction that inflates net income, as contrasted to inclusion of Construction Work in Progress in the rate base, which results in real money income. Where AFUDC remains a small portion of net income, little difficulty is caused. However, when AFUDC represents the majority of net income, the picture is different.

With large construction programs continuing, although on a declining basis, and with interest rates at high levels, the AFUDC problem is a very real one. The Top 100 utilities did perform better in 1981 than in 1980, but the quality of that income is not what it should be.

Overall, 88 utilities reported net income gains for 1981 compared to 74 a year ago. Median net income change for the Top 100 was 22.6 percent in 1981, more than double that for the Top 100 in 1980 — 10.5 percent.

Shareholder earnings improve

Per-share earnings performance of

FINANCIAL STATISTICS

Company	Net Income		Revenue		Sales (KWH)		Int. Cov. Ratio		Earnings Per Share	Price/Share 1981 (Dollars)		% Change Long Term Debt
	Rank	% Gain	Rank	% Gain	Rank	% Gain	1981	1980	1981	High	Low	1981
San Diego Gas & Electric	1	165.8	25	20.7	21	3.7	1.24	0.58	$2.34	14.000	11.000	−0.69
Nevada Power	2	134.8	76	10.6	8	10.0	2.18	[illegible]	$3.46	22.875	18.250	33.34
Puget Sound Power & Light	3	117.5	55	14.1	18	4.4	1.58	1.06	$2.85	14.000	12.250	22.44
Savannah Electric & Power	4	109.8	73	11.0	39	1.5	1.21	0.77	$2.39	12.875	8.875	31.30
Florida Power	5	90.6	5	31.8	24	3.5	2.20	1.82	$2.80	16.375	12.375	12.25
Washington Water Power	6	67.1	84	9.4	10	10.0	1.99	1.49	$3.29	18.375	15.625	14.96
Central Vermont Public Service	7	67.1	10	29.3	5	10.4	3.66	2.21	$3.74	17.750	12.750	17.95
Kentucky Utilities	8	65.8	40	17.4	73	−1.6	1.31	1.16	$2.17	17.000	14.375	10.33
Southern California Edison	9	64.5	74	10.7	19	4.2	1.86	1.16	$4.93	30.625	22.875	15.40
Public Service of New Mexico	10	64.4	28	19.8	12	6.6	2.41	2.28	$4.23	24.875	19.250	24.73
Ohio Edison	11	61.6	35	18.4	7	10.1	0.90	0.86	$2.30	13.500	11.000	10.37
Tucson Electric Power	12	61.3	83	9.5	9	10.0	3.10	2.84	$3.80	18.875	13.375	3.02
Dayton Power & Light	13	58.5	27	19.9	44	1.2	2.14	1.65	$2.51	14.875	12.000	16.08
Pennsylvania Power & Light	14	52.2	12	28.0	31	2.0	1.03	1.08	$3.17	18.375	14.750	19.52
Missouri Public Service	15	51.6	88	8.6	88	−3.7	1.76	1.65	$2.55	11.500	9.000	11.61
Rochester Gas & Electric	16	50.6	20	22.1	75	−1.8	2.17	1.56	$2.93	16.000	11.750	9.92
United Illuminating	17	47.7	18	23.9	86	−3.5	2.27	1.16	$4.24	20.750	17.750	2.70
Arizona Public Service	18	44.3	50	15.2	4	12.7	1.93	2.30	$3.26	19.625	15.125	11.71
Middle South Utilities	19	43.7	36	18.3	90	−3.8	1.09	0.88	$2.44	13.875	11.000	14.86
Toledo Edison	20	43.2	80	10.1	83	−3.2	1.88	1.53	$3.27	18.375	15.125	7.06
Montana-Dakota Utilities	21	42.5	11	29.2	14	5.6	3.02	2.24	$2.89	23.250	16.250	−6.63
El Paso Electric	22	41.4	31	18.9	67	−0.8	4.90	5.92	$2.23	11.000	9.875	24.80
Montana Power	23	41.0	87	8.8	47	0.9	2.01	1.56	$4.04	36.375	24.500	39.15
Iowa-Illinois Gas & Electric	24	40.8	71	11.4	55	0.4	2.24	2.33	$3.45	18.375	15.125	19.40
Niagara Mohawk Power	25	39.9	24	21.0	46	0.9	1.67	1.47	$2.35	13.750	10.750	2.68
Consolidated Edison	26	39.0	19	23.3	70	−1.2	3.71	2.72	$6.44	33.625	22.625	−2.75
Eastern Utilities Associates	27	38.3	21	21.8	72	−1.5	1.31	0.73	$2.03	12.500	10.250	15.85
Portland General Electric	28	36.3	23	21.3	6	10.3	1.25	1.14	$2.54	14.500	11.000	1.39
South Carolina Electric & Gas	29	35.2	26	20.4	61	−0.4	2.21	1.87	$2.44	16.000	12.500	4.71
Wisconsin Electric Power	30	31.1	52	14.4	56	0.4	2.68	2.36	$4.39	29.250	20.375	−0.34
Gulf States Utilities	31	30.6	22	21.5	51	0.5	1.39	1.92	$2.24	12.750	10.500	15.63
Central Hudson Gas & Electric	32	29.2	3	35.6	2	16.3	1.90	1.77	$3.72	19.000	16.000	5.03
Detroit Edison	33	28.5	60	13.3	65	−0.6	0.89	0.97	$2.02	12.750	10.875	12.39
Public Service of Indiana	34	28.2	70	11.5	64	−0.6	3.20	3.16	$3.42	22.500	18.250	22.69
Philadelphia Electric	35	27.9	51	14.6	29	2.3	1.90	1.88	$2.25	14.375	11.125	15.76
Allegheny Power System	36	27.7	2	38.6	1	26.6	2.31	1.74	$3.03	17.250	13.000	1.40
Central Illinois Light	37	27.3	75	10.7	96	−4.7	3.02	2.51	$2.40	15.625	12.250	−6.81
Houston Lighting & Power	38	27.0	8	30.4	20	3.8	3.05	2.98	$3.14	21.750	16.625	14.12
Carolina Power & Light	39	27.0	17	24.9	49	0.7	1.82	1.74	$3.06	20.750	16.750	12.60
Central Maine Power	40	26.9	90	7.9	16	4.9	1.39	1.53	$1.81	13.250	11.375	26.78
Central Louisiana Electric	41	26.8	37	18.2	81	−2.6	1.19	1.30	$2.46	14.625	12.750	−3.85
Public Service of New Hampshire	42	26.6	15	25.5	80	−2.5	1.64	3.21	$2.65	16.500	14.125	7.26
Minnesota Power & Light	43	26.2	69	11.7	57	0.3	2.48	1.78	$3.05	19.250	15.000	−3.20
Oklahoma Gas & Electric	44	25.8	44	16.5	43	1.2	2.19	1.91	$2.05	14.500	12.000	−1.70
Pacific Power & Light	45	23.9	4	32.1	17	4.7	1.04	1.05	$2.82	21.875	16.000	9.32
Central Illinois Public	46	23.7	95	5.4	94	−4.4	3.82	3.51	$1.73	12.125	10.000	−1.88
Cleveland Electric Illuminating	47	23.7	59	13.4	87	−3.6	1.41	1.36	$2.52	16.500	13.630	9.65
Duquesne Light	48	23.4	48	15.6	25	2.5	1.51	1.58	$2.06	14.125	11.375	10.89
Kansas Gas & Electric	49	22.8	92	6.6	97	−4.7	2.93	2.21	$2.85	16.500	13.750	34.47
New York State Electric & Gas	50	22.6	30	18.9	26	2.4	2.09	1.84	$2.96	16.250	13.875	4.57
Commonwealth Edison	51	22.5	67	12.4	74	−1.6	0.67	0.68	$3.06	22.375	17.750	10.49
Atlantic City Electric	52	21.9	7	31.1	48	0.7	2.76	2.97	$3.03	18.250	15.250	10.16
Interstate Power	53	21.2	53	14.3	11	9.6	2.32	1.78	$2.07	13.875	11.000	−0.08
Texas Utilities	54	20.7	14	25.9	59	−0.2	2.49	2.24	$3.51	22.125	16.250	7.36
Long Island Lighting	55	20.6	9	30.4	71	−1.3	2.16	1.58	$2.55	15.750	13.875	19.74
Public Service of Colorado	56	20.1	47	15.6	34	1.8	2.65	2.32	$1.97	15.000	12.750	3.09
New England Electric System	57	19.2	39	17.6	63	−0.5	1.98	1.97	$4.05	26.875	18.875	5.14
Wisconsin Power & Light	58	18.7	66	12.5	95	−4.4	2.98	2.92	$3.05	21.500	15.500	15.61
Northern States Power	59	17.3	77	10.5	37	1.7	3.07	3.08	$3.89	27.000	20.000	7.39
Iowa Resources	60	16.2	79	10.2	92	−4.2	1.28	1.98	$3.54	23.375	19.375	5.01
Kansas City Power & Light	61	16.2	94	5.8	84	−3.2	2.67	2.83	$4.83	24.750	19.500	12.69
Delmarva Power & Light	62	16.1	41	16.9	69	−0.9	1.73	1.25	$1.78	12.750	10.500	4.65
Florida Power & Light	63	16.1	6	31.6	23	3.5	1.52	1.72	$4.25	32.000	23.875	13.39
Illinois Power	64	13.8	85	9.2	76	−1.9	2.22	2.31	$2.84	21.375	16.625	−1.99
Hawaiian Electric	65	13.8	1	54.7	45	1.1	1.64	1.87	$3.92	26.750	20.500	0.34
Kansas Power & Light	66	13.4	93	6.4	91	−4.1	3.57	3.67	$3.30	20.000	16.125	4.31
Boston Edison	67	13.2	34	18.4	41	1.3	1.71	2.01	$4.15	24.500	19.500	−2.36
Sierra Pacific Power	68	13.0	49	15.3	3	13.1	1.26	1.23	$1.48	13.250	10.125	19.75
Cincinnati Gas & Electric	69	12.5	61	13.2	35	1.8	1.46	1.51	$2.30	17.375	14.000	10.62
Central Telephone & Utilities	70	12.2	89	8.3	98	−7.2	3.41	3.21	$3.89	35.750	23.500	0.61
Central & South West	71	10.5	32	18.7	32	1.9	2.98	3.23	$2.54	15.375	12.000	10.15
Duke Power	72	10.2	58	13.6	27	2.4	2.11	2.21	$3.19	22.500	15.875	−1.86
Northern Indiana Public Service	73	10.2	57	13.9	54	0.4	1.55	1.77	$1.37	12.375	10.125	7.59
Southwestern Public Service	74	9.8	63	12.8	53	0.5	2.56	2.73	$1.80	13.125	10.500	9.54
Iowa Electric Light & Power	75	9.4	78	10.2	62	−0.5	1.34	1.55	$1.97	14.250	11.125	10.49
Idaho Power	76	9.4	54	14.1	22	3.5	1.13	1.21	$3.05	22.500	19.000	4.43
Orange & Rockland	77	9.1	56	14.0	85	−3.3	2.19	2.21	$2.35	14.625	11.625	−4.72
Consumers Power	78	8.6	33	18.7	50	0.6	0.87	0.97	$3.12	19.250	15.875	−2.78
Wisconsin Public Service	79	8.5	64	12.8	36	1.7	3.51	3.84	$3.00	20.500	14.750	−2.86
Utah Power & Light	80	7.9	86	9.0	78	−2.3	2.17	2.41	$2.29	20.000	15.000	19.62
Northeast Utilities	81	7.2	16	25.0	58	0.0	0.85	1.05	$1.29	9.750	8.000	3.38
American Electric Power	82	6.8	68	11.8	40	1.3	1.24	1.26	$2.37	18.375	15.375	5.97
Louisville Gas & Electric	83	6.4	72	11.3	79	−2.4	2.32	2.61	$2.71	18.875	16.000	10.07
Potomac Electric Power	84	5.1	43	16.9	42	1.3	2.16	2.45	$2.14	15.500	11.875	0.49
Baltimore Gas & Electric	85	5.1	46	15.9	30	2.1	2.57	2.64	$3.70	25.375	19.750	2.74
Pacific Gas & Electric	86	3.7	38	17.8	13	5.8	1.58	1.68	$3.41	24.125	19.500	8.37
Union Electric	87	2.0	97	2.6	77	−2.1	1.30	1.87	$1.90	11.875	9.875	16.27
Iowa Public Service	88	0.5	42	16.9	89	−3.8	1.60	1.81	$2.70	20.000	17.250	12.28
General Public Utilities	89	−0.2	65	12.8	52	0.5	0.21	0.17	$0.33	6.875	3.875	0.54
Teco Energy	90	−0.5	29	19.2	28	2.4	2.63	3.28	$3.00	22.750	16.500	3.82
Virginia Electric & Power	91	−2.0	99	2.0	38	1.7	1.05	1.19	$1.77	13.125	10.125	9.45
Southern Indiana Gas & Electric	92	−2.4	91	7.1	82	−3.1	3.13	4.42	$3.32	20.000	16.125	34.16
Southern Company	93	−5.3	62	13.1	33	1.9	1.18	1.29	$1.81	12.875	10.875	10.28
Public Service Electric & Gas	94	−9.7	45	16.0	68	−0.8	1.92	2.17	$2.63	20.125	16.500	3.94
Empire District Electric	95	−13.3	96	4.5	99	−8.3	1.49	1.86	$1.33	11.500	9.750	0.00
Texas-New Mexico Power	96	−14.7	13	27.3	18	5.3	0.00	0.00	$2.39	18.750	15.500	3.39
Indianapolis Power & Light	97	−19.4	98	0.8	60	−0.4	1.93	2.77	$2.81	23.875	18.000	17.82
Otter Tail Power	98	−22.7	82	9.9	66	−0.8	1.00	1.44	$1.72	19.250	15.625	0.96
Madison Gas & Electric	99	−23.0	100	0.2	100	−12.7	2.65	3.60	$1.66	15.750	12.000	−1.56
Commonwealth Energy System	100	−24.2	81	9.9	93	−4.3	1.78	2.54	$2.22	16.875	12.375	9.18

ALPHABETICAL LISTING OF COMPANY PERFORMANCES

	Electric Sales		Customers Served				Revenues			
			Electric		Gas					
Company	Rank	KWH Sales (millions)	Total (1,000's)	% Gain	Total (1,000's)	% Gain	Total (1,000's)	% Electric	% Gas	Net Income After Tax (1,000's)
Allegheny Power Systems	12	44,586	1,137	1.21	0	0.00	$1,607,461	100.00	0.00	$132,477
American Electric Power	1	113,011	2,511	0.92	69	2.45	$4,192,645	97.06	2.02	$368,279
Arizona Public Service	44	13,388	439	4.04	341	0.28	$ 882,154	82.84	17.16	$170,048
Atlantic City Electric	76	5,675	366	1.32	0	0.00	$ 469,683	100.00	0.00	$ 39,457
Baltimore Gas & Electric	33	17,584	848	1.35	512	0.38	$1,421,056	65.74	32.93	$123,243
Boston Edison	48	12,024	611	1.35	0	0.00	$1,049,596	93.25	0.00	$ 58,462
Carolina Power & Light	17	30,487	758	2.14	0	0.00	$1,343,558	100.00	0.00	$160,937
Central & South West	10	47,850	1,381	3.27	0	0.00	$2,055,318	100.00	0.00	$204,495
Central Hudson Gas & Electric	77	5,522	213	1.25	45	2.69	$ 444,881	89.55	10.45	$ 25,553
Central Illinois Light	80	4,727	186	0.03	164	0.53	$ 436,971	63.85	36.15	$ 27,959
Central Illinois Public Service	59	8,380	305	0.68	148	1.94	$ 529,391	80.73	19.27	$ 51,927
Central Louisiana Electric	81	4,700	180	2.77	0	0.00	$ 260,642	98.40	0.00	$ 23,043
Central Maine Power	71	6,348	389	1.57	0	0.00	$ 365,378	98.99	0.00	$ 26,195
Central Telephone & Utilities	94	2,803	132	1.03	0	0.00	$ 138,701	99.30	0.00	$ 10,051
Central Vermont Public Service	98	2,112	114	2.47	0	0.00	$ 117,339	98.33	0.00	$ 11,367
Cincinnati Gas & Electric	41	14,786	597	0.91	367	0.39	$1,081,473	63.16	36.84	$ 77,825
Cleveland Electric Illuminating	34	17,508	711	0.11	0	0.00	$1,012,930	98.80	0.00	$120,817
Commonwealth Edison	5	61,229	2,967	0.63	0	0.00	$3,737,311	100.00	0.00	$351,803
Commonwealth Energy System	78	5,304	279	4.29	199	2.00	$ 563,455	64.10	33.20	$ 17,369
Consolidated Edison	18	30,302	2,739	0.58	1,017	−0.65	$4,865,934	81.73	11.24	$407,438
Consumers Power	23	25,684	1,339	0.82	1,159	1.85	$2,733,973	51.19	46.26	$181,404
Dayton Power & Light	55	10,288	420	0.25	265	0.39	$ 779,586	70.46	28.61	$ 74,755
Delmarva Power & Light	64	7,395	286	3.62	74	1.33	$ 608,504	82.85	13.65	$ 45,893
Detroit Edison	14	34,013	1,767	0.17	0	0.00	$2,054,057	97.91	0.00	$176,787
Duke Power	8	53,548	1,307	1.74	0	0.00	$1,927,822	86.72	0.00	$278,356
Duquesne Light	43	13,630	556	0.57	0	0.00	$ 796,847	98.64	0.00	$ 85,896
Eastern Utilities Associates	83	4,288	228	0.89	0	0.00	$ 297,931	96.96	0.00	$ 12,437
El Paso Electric	90	3,699	186	3.02	0	0.00	$ 250,379	99.59	0.00	$ 40,579
Empire District Electric	96	2,318	100	1.48	0	0.00	$ 91,858	99.61	0.00	$ 5,776
Florida Power & Light	11	46,263	2,336	3.93	0	0.00	$3,088,620	98.27	0.00	$188,596
Florida Power	30	19,457	824	3.66	0	0.00	$1,278,297	97.10	0.00	$ 95,070
General Public Utilities	16	32,012	1,598	1.24	0	0.00	$2,065,487	99.85	0.00	$ 20,544
Gulf States Utilities	21	27,810	517	3.35	86	0.52	$1,221,714	90.57	3.08	$120,550
Hawaiian Electric	72	6,201	286	1.22	0	0.00	$ 665,151	99.90	0.00	$ 25,976
Houston Lighting & Power	7	56,880	1,118	7.99	0	0.00	$2,769,215	100.00	0.00	$225,200
Idaho Power	49	11,861	257	1.66	0	0.00	$ 289,706	100.00	0.00	$ 41,875
Illinois Power	42	14,213	525	0.82	383	0.43	$ 964,292	64.40	35.60	$107,516
Indianapolis Power & Light	57	8,777	332	1.83	0	0.00	$ 336,584	93.79	0.00	$ 39,187
Interstate Power	87	4,048	155	0.61	45	1.43	$ 259,970	71.09	28.91	$ 16,506
Iowa Electric Light & Power	88	3,969	204	0.48	131	0.95	$ 345,590	63.57	34.50	$ 19,463
Iowa-Illinois Gas & Electric	86	4,063	173	0.59	222	0.19	$ 416,796	45.42	54.58	$ 37,571
Iowa Resources	85	4,170	231	0.29	133	0.19	$ 328,261	67.06	32.36	$ 31,126
Iowa Public Service	92	3,124	159	0.45	122	0.75	$ 325,793	61.62	38.28	$ 25,679
Kansas City Power & Light	60	8,319	349	1.33	0	0.00	$ 471,711	98.75	0.00	$ 65,397
Kansas Gas & Electric	63	7,468	233	1.93	0	0.00	$ 313,093	99.65	0.00	$ 53,060
Kansas Power & Light	65	7,276	278	1.06	133	1.38	$ 410,090	74.03	25.97	$ 48,669
Kentucky Utilities	53	10,603	364	1.46	0	0.00	$ 438,291	99.53	0.00	$ 29,952
Long Island Lighting	45	13,387	908	0.88	396	0.86	$1,664,832	84.26	15.74	$198,902
Louisville Gas & Electric	62	7,600	296	0.47	233	0.21	$ 494,932	63.99	35.81	$ 34,738
Madison Gas & Electric	99	1,961	99	1.98	68	2.27	$ 162,082	57.28	42.30	$ 9,542
Middle South Utilities	9	53,035	1,570	1.52	241	−0.08	$2,771,788	93.18	5.02	$281,483
Minnesota Power & Light	58	8,593	115	5.03	9	−1.11	$ 369,259	97.02	2.50	$ 34,921
Missouri Public Service	95	2,397	134	1.06	40	−0.49	$ 166,311	82.03	17.48	$ 14,091
Montana-Dakota Utilities	100	1,642	111	3.22	170	3.23	$ 288,495	28.57	50.53	$ 21,650
Montana Power	61	7,797	229	1.48	103	−0.37	$ 490,239	42.84	31.10	$ 53,662
Nevada Power	74	5,814	199	5.32	0	0.00	$ 244,674	100.00	0.00	$ 29,148
New England Electric System	36	16,682	1,072	1.54	0	0.00	$1,282,102	98.50	0.00	$ 90,983
New York State Electric & Gas	51	11,016	670	0.92	129	1.16	$ 767,539	79.37	20.63	$ 90,265
Niagara Mohawk Power	15	32,890	1,361	0.07	428	1.18	$2,150,718	79.97	20.03	$186,358
Northeast Utilities	29	20,557	1,080	1.10	152	1.16	$1,665,057	88.01	10.95	$ 95,118
Northern Indiana Public Service	46	12,997	361	−0.25	527	0.96	$1,556,255	45.75	54.25	$ 60,658
Northern States Power	22	25,784	1,100	1.43	276	2.28	$1,280,889	77.92	21.23	$114,037
Ohio Edison	24	24,662	963	0.58	0	0.00	$1,279,649	100.00	0.00	$163,892
Oklahoma Gas & Electric	28	21,343	591	2.84	0	0.00	$ 826,117	100.00	0.00	$ 67,129
Orange & Rockland	91	3,462	209	1.65	88	1.97	$ 425,099	73.92	25.73	$ 30,372
Otter Tail Power	93	2,840	120	1.45	0	0.00	$ 118,104	100.00	0.00	$ 8,267
Pacific Gas & Electric	4	61,669	3,515	1.95	2,897	1.38	$6,194,575	63.05	33.10	$430,907
Pacific Power & Light	26	24,083	652	1.34	0	0.00	$1,268,553	55.10	0.00	$137,176
Pennsylvania Power & Light	27	22,954	1,007	0.70	0	0.00	$1,133,278	99.37	0.00	$183,182
Philadelphia Electric	20	28,268	1,324	0.77	293	3.26	$2,433,425	82.27	14.65	$223,761
Portland General Electric	39	15,307	502	2.31	0	0.00	$ 594,789	98.16	0.00	$ 98,968
Potomac Electric Power	35	16,769	522	2.95	0	0.00	$1,000,510	99.61	0.00	$ 93,297
Public Service of Colorado	37	15,473	846	3.12	701	3.04	$1,336,171	55.54	43.59	$ 84,094
Public Service of Indiana	31	18,790	541	0.87	0	0.00	$ 720,126	99.20	0.00	$129,028
Public Service of New Hampshire	73	6,075	290	0.13	0	0.00	$ 440,884	98.90	0.00	$ 58,018
Public Service of New Mexico	75	5,761	218	2.09	0	0.00	$ 336,165	98.16	0.00	$ 88,095
Public Service Electric & Gas	19	29,961	1,694	0.20	1,310	0.22	$3,471,652	66.89	33.11	$212,599
Puget Sound Power & Light	38	15,413	562	3.09	0	0.00	$ 408,747	100.00	0.00	$ 84,048
Rochester Gas & Electric	70	6,686	290	1.62	228	6.94	$ 613,541	61.06	34.64	$ 65,750
San Diego Gas & Electric	54	10,402	792	2.52	514	1.92	$1,159,662	81.70	18.19	$ 91,438
Savannah Electric & Power	97	2,293	90	1.89	0	0.00	$ 135,618	99.78	0.00	$ 8,900
Sierra Pacific Power	89	3,773	174	2.72	53	1.76	$ 269,784	81.40	13.71	$ 18,787
South Carolina Electric & Gas	50	11,763	351	1.74	169	1.70	$ 759,687	74.91	24.77	$ 68,622
Southern California Edison	3	62,451	3,233	2.17	1	1.25	$4,055,087	99.98	0.01	$422,024
Southern Company	2	94,217	2,620	2.11	0	0.00	$4,256,237	99.32	0.00	$325,979
Southern Indiana Gas & Electric	84	4,254	104	1.26	63	1.11	$ 220,260	71.90	26.08	$ 17,819
Southwestern Public Service	47	12,369	305	2.83	0	0.00	$ 546,595	99.62	0.00	$ 55,147
Teco Energy	52	10,830	339	3.64	0	0.00	$ 641,452	96.72	0.00	$ 47,592
Texas-New Mexico Power	79	5,287	170	4.10	0	0.00	$ 275,439	100.00	0.00	$ 5,136
Texas Utilities	6	58,372	1,630	4.57	0	0.00	$2,738,377	99.60	0.00	$359,398
Toledo Edison	66	7,151	269	0.59	5	3.50	$ 442,284	98.32	1.06	$ 70,402
Tucson Electric Power	68	7,106	198	3.83	0	0.00	$ 350,468	99.50	0.00	$ 82,613
Union Electric	25	24,279	987	1.00	108	1.05	$1,105,536	92.23	6.59	$127,605
United Illuminating	82	4,548	283	0.74	0	0.00	$ 451,022	99.60	0.00	$ 37,187
Utah Power & Light	40	15,065	465	7.83	0	0.00	$ 663,989	99.88	0.00	$ 92,408
Virginia Electric & Power	13	38,906	1,381	2.82	121	1.08	$2,161,853	95.74	4.26	$180,614
Washington Water Power	56	9,610	228	2.77	78	1.89	$ 317,661	60.17	38.09	$ 39,474
Wisconsin Electric Power	32	17,792	813	0.81	216	1.53	$1,152,383	75.49	23.70	$ 90,415
Wisconsin Power & Light	67	7,121	304	1.17	102	2.15	$ 454,516	73.98	25.35	$ 35,538
Wisconsin Public Service	69	6,795	266	2.02	152	1.32	$ 492,262	59.83	40.17	$ 32,438

the Top 100 Electric Utilities improved in 1981 and was substantially better than in 1980. Gainers outnumbered losers. Average earnings per-share jumped markedly and the bulk of companies that in 1981 suffered continuing or repetitive annual declines recovered in 1981.

In 1981, 72 utilities enjoyed gains in per-share earnings from 1980, while 26 reported declines. In 1980, as in 1979, 56 companies posted gains and 42 companies suffered declines.

For the 99 companies that reported earnings results in 1981, the average increase per-share was 30 cents, an increase of 11.9 percent from 1980 and three-times the cumulative increase (10 cents) from 1977 through 1980.

TABLE III
THE TOP 10 INCOME PRODUCERS

(Net After-Tax Available for Common)

Rank			Income	'81%
'81	'80	Company	(millions)	Change
1	1	Pacific Gas & Electric	$430.9	3.7
2	7	Southern California Edison	$422.0	64.5
3	5	Consolidated Edison	$407.4	39.0
4	2	American Electric Power	$368.3	6.8
5	4	Texas Utilities	$359.4	20.7
6	6	Commonwealth Edison	$351.8	22.5
7	3	Southern Company	$326.0	−5.3
8	10	Middle South Utilities	$281.5	43.7
9	8	Duke Power	$278.4	10.2
10	13	Houston Lighting & Power	$225.2	27.0

The arithmetic average change in per-share earnings in 1981 was 14.72 percent, compared with 3.70 percent in 1980 and 2.45 in 1979.

The median rate of change, 10.38, also was well above the median for 1980 — 2.85 percent — and for 1979 — 1.97 percent.

As in previous reports, the companies recording the largest per-share earnings gains were recovering from a bad year previous. So it was in 1981. Eight of the first 25 in 1981 were in the bottom 25 in 1980, ten ranked 51-75 in 1980, four ranked between 26 and 50 and two were repeaters in the first 25 from a year ago. One (Montana-Dakota Utilities) was unranked (not in the Top 100 in 1980).

Another indication of the improved financial performance is that the majority of companies that had suffered repeated years of earnings problems reversed their situations in 1981. Kentucky Utilities, which had suffered earnings declines in four of the last five years, rebounded into 10th place with a gain of 43.71 percent. Only General Public Utilities, still burdened with both units of the Three Mile Island nuclear plant down, and clean up costs for TMI-2 increasing, suffered a fourth consecutive year of earnings decline.

Return on equity

At the end of 1981, the average return on equity *allowed* was 15.14 percent, up from 13.88 for 1980. Unfortunately, average return on equity *earned* in 1981 was 12.65 percent, as compared to 11.33 percent in 1980.

Thus, the spread between *allowed return on equity and earned* return on equity narrowed slightly. But earned returns in 1981 still fell shy of allowed return in 1980 by nearly 10 percent and at 12.65 percent, remained 16.7 percent below the level allowed for 1981.